RULES AND CONTRACTS OF THE ELECTRICITY MARKET OF THE REPUBLIC OF ARMENIA

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WHOLESALE ELECTRICITY MARKET TRADING RULES OF THE REPUBLIC OF ARMENIA

SECTION 1. GENERAL PROVISIONS

CHAPTER 1. SUBJECT AND DEFINITIONS

1. The Republic of Armenia (RoA) Wholesale Electricity Market Trading Rules (hereinafter: WEM Rules) shall define the structure and principles of functioning of the Wholesale Electricity Market (WEM), the procedure for registration of WEM Participants, the trading rules, Orders submission procedures, procedures for import and export of electricity, principles of the functioning of Bilateral Contracts, the Day-Ahead and Balancing Markets, procedures on the provision of and payment for electricity and capacity supply and System services, requirements for the storage and transparency of WEM data, the rules and procedures aimed at increasing the efficiency of the WEM's operation, as well as other rules required for the well-organized, normal, and efficient operation of the WEM.
2. The main definitions used in these WEM Rules:

1) Trading (Settlement) Period	A period of 60 minutes' duration.
2) Commercial Metering	Metering of electricity (capacity) quantities and provided services subject to payment within the framework of the trading relations of WEM Participants.
3) Commercial Meter	A metering device for commercial measurement of electricity (capacity) quantities stated in the WEM Contract.
4) Trading day (TD)	A sequence of consecutive Trading periods from 00:00 until 23:59.
5) Generator	An entity that is eligible for electricity (capacity) generation and is in the state of performing the electricity generation activity.
6) Export Point	Crossing point of the interconnection line and the state border, where the export of electricity is carried out.
7) Distribution Network	A unified system of electricity distribution lines, substations, and other facilities controlled and operated by the Distributor.
8) EDN Code	The RoA Electricity Market Distribution Network (EDN) Code approved by the Commission.
9) Distributor	An entity holding an electricity (capacity) distribution license.
10) Confidential Information	Information on commercial status or financial secrets of a WEM Participant and/or other information, the public disclosure of which may harm the latter, as well as customer-related information available from the WEM Participants.

11) Transaction	An agreement between the WEM Trade Participants with respect to electricity trading in all segments and components of the WEM or a direct contract signed between a WEM Participant with a foreign physical or legal entity on the export of electricity or on the import of electricity to be sold in the WEM or to be used to satisfy its own demand.
12) Universal Supplier	An entity holding a universal supplier license.
13) Annual Adequacy Forecast (AAF)	A complex of annual forecasted indicators of electricity consumption, losses, and own needs, generation, import, and export defined by the WEM Rules.
14) WEM Participants	Generator, Universal Supplier, Supplier, Trader, Qualified Customer, Transmitter, Distributor, System Operator, and Market Operator.
15) WEM Trade Participants	Generator, Universal Supplier, Supplier, Trader, Qualified Customer, and Transmitter, Distributor in terms of electricity purchased to cover own needs and losses.
16) WEM Contract	A contract between WEM Participants for participation in the WEM.
17) Autonomous Power Producer (APP)	A legal or physical entity generating electricity for own needs and possessing energy facilities with installed capacity not exceeding the overall installed capacity of its electricity consumption devices and the level defined in the Energy Law (hereinafter: Law).
18) AMIR	The cross-border interconnection line comprising high-voltage transmission lines and other plants and apparatus as necessary that connects the electricity systems of Armenia and Iran.
19) Transmission network	The unified system of electricity transmission lines (including substations and other facilities), under the management and operation of the Transmitter, through which electricity is transmitted to the distribution network and customers, exported (imported), and/or transited to a third country.
20) Transmitter	An entity holding an electricity (capacity) transmission license.
21) ETN Code	The RoA Electricity Market Transmission Network Code approved by the Commission.
22) System Services	Services to be provided by the WEM Participants for reliable and safe operations of the electricity system in cases and procedures defined in the ETN Code.
23) Electricity System Operator (ESO)	An entity holding an Electricity System Operator license.
24) Order	An offer to sell and/or a bid to buy electricity submitted in accordance with the WEM Rules.
25) Commission	The Public Services Regulatory Commission of the Republic of Armenia.
26) Metering Point	Commercial and control metering points specified in the WEM Contract.

27) Metering Complex	A set of combined devices (current and potential transformers, electricity meters, impulse sensors, modems, adders and connection wires, and standalone power devices ensuring uninterruptible power supply for at least 1.5 hours connected to each other on the scheme approved by the design) for measurement and metering of electricity (capacity).
28) Metering Data	The quantity of electricity metered and recorded by a Metering Complex.
29) Balancing Service	A type of System Service envisaged by the ETN Code.
30) Balancing Market (BALM)	A segment of the WEM where Balancing energy is traded.
31) Balancing Energy	The difference between the quantity of electricity sold and purchased on the Bilateral Contracts and Day-Ahead Markets as a result of dispatching the system in real-time, and quantities of electricity that have been actually purchased and sold (including imported and exported or transited) within the same Trading Period, which shall be calculated according to the WEM Rules.
32) GEAM interconnection	The cross-border interconnection line comprising high-voltage transmission lines and other plant and apparatus as necessary that connects the electricity systems of Armenia and Georgia.
33) REM Rules	The Republic of Armenia Retail Electricity Market Trading Rules approved by the Commission.
34) Supplier	An entity holding an electricity supply license.
35) Import Point	A crossing point on the interconnection line through which the import of electricity is implemented.
36) Market Management System (MMS) User	A responsible entity (entities) appointed by a WEM Participant, except for the Market Operator.
37) Electricity Market Operator (EMO)	An entity holding the electricity market operator services license.
38) Qualified Customer	A customer recognized by the EMO as qualified based on satisfying the criteria defined by the WEM Rules.
39) Bilateral Contracts Market	A segment of the WEM where electricity trade is conducted based on direct contracts for the purchase and sale of electricity signed between the WEM Trade Participants.
40) Contractual Capacity	The annual capacity (by months) stated in the contract between an IPP plant and the Universal Supplier.
41) Boundary Point	The border of balance ownership of electric installations of the WEM Trade Participants.
42) Control Meter	Electricity control metering device specified in the WEM Contract.
43) Transit	Transit transmission of electricity through the customs area of the RoA from the entry customs authority to the exit customs authority.

44) Available Capacity	Maximum capacity subject to Dispatch by the ESO, which is determined by reducing the nominal capacity by the capacity of limitations resulting from climatic conditions at thermal power plants (TPPs) and ANPP (external air temperature, humidity, location altitude), water flow and pressure at HPPs, as well as deterioration of main equipment, thermal load, and residual physical resources.
45) Clearing Price	A price formed in the Day-Ahead Market per Trading Period of each Trading Day.
46) Day-Ahead Market (DAM)	A segment of the WEM where electricity trade is conducted based on the Transactions concluded on the day before the day of the actual delivery of electricity.

CHAPTER 2. OBJECTIVE AND PRINCIPLES OF WEM OPERATION

3. The objectives of WEM operation according to these Rules are as follows:
   1) To ensure gradual liberalization of the WEM, establishing flexible mechanisms of electricity trade;
   2) To support the improvement of the RoA electricity system competitiveness and investment environment;
   3) To create transparent and competitive conditions for WEM operation, encouraging new WEM Participants to enter the wholesale market;
   4) To promote cross-border trade.
4. WEM operation is based on the following fundamental principles:
   1) Implementing electricity trade in various segments of the WEM;
   2) Ensuring adequate conditions for economic competition in non-regulated segments of the WEM;
   3) Applying accountability mechanisms for violation of responsibilities under WEM Rules and Transactions, as well as for imbalances caused by a WEM Participant;
   4) Establishing transparent and non-discriminatory conditions for import, export, transit of electricity, and power flow exchange with regional systems;
   5) Export of electricity only after the domestic demand for electricity is satisfied;
   6) Authenticity and accessibility of information submitted by WEM Participants to the ESO and the EMO;
   7) Encouraging generation of electricity from renewable sources either by REPPs or APPs;
   8) Ensuring non-discriminatory access to the Transmission and Distribution Networks in the WEM.

CHAPTER 3. INFORMATION SUBMISSION AND NOTIFICATION

5. The exchange of information among the WEM Participants as well as the submission of documents shall be performed appropriately.
6. The exchange of information and submission of documents shall be deemed appropriately performed if they have been handed personally with acknowledgment of receipt, or using a document sharing platform (if such is available for the recipient of that correspondence), or by a registered letter (including with a notice of delivery), by email (including the email specified by the WEM Participant) or other means of communication securing the integrity of the message (including sending a message to a phone number specified by the WEM Participant), as well as through other electronic communication means defined by legislation, or if they have been handed with a mail delivery confirmation, unless otherwise specifically mentioned in the WEM Rules. In case the EMO is notified through the MMS tool, the data presented shall be deemed appropriately notified by the given WEM Participant to other WEM Participants whom it may concern.

7. The WEM Participants shall be liable for the accuracy of information (documents) provided in the WEM.
8. Where inaccuracies were revealed in the information or documents provided by a WEM Participant, those should be corrected within 3 business days after the inaccuracies were revealed and the parties notified each other unless another term is specified in the WEM Rules.
9. In cases provided for by the WEM Rules, the EMO and the ESO shall ensure the complete publication of information in the MMS provided by WEM Trade Participants.
10. The WEM Participant shall respond to the inquiries, applications, complaints, or suggestions of other WEM Participants within 5 business days from receipt of such unless another term is defined by the WEM Rules for the specific cases.
11. The information (document) shared by the WEM Participants with each other as well as that presented to the Commission shall be in the public domain if it is not deemed confidential under the law.
12. The information (documents) defined in Provision 11 of the WEM Rules may be published in the manner prescribed by law. The party that published it shall be responsible for violating the requirements of the legislation through the publication of such information (documents).
13. Any information or document provided in the context of the WEM Rules shall be preserved for at least 5 years unless another longer period is defined by the WEM Rules or legislation for the storage of the given type of documents and data.

CHAPTER 4. EMERGENCY SITUATIONS

14. In cases defined by the ETN Code, when an Emergency Situation is declared, the WEM Participants shall operate exclusively based on the dispatch instructions of the ESO. The obligations assumed under Transactions shall be suspended for the entire period of the Emergency Situation and measures defined by the WEM Rules for violation thereof shall not be undertaken.
15. In Emergency Situations, electricity shall be sold at the maximum price defined by the Commission for the Balancing Service Providing Generator, except for those plants for which the Commission has set a tariff. For these plants, the sale of electricity shall be performed at the tariff set by the Commission. At the same time, electricity shall be purchased at the actually formed average weighted price of electricity sale.
16. Within 10 business days after the ESO declares the end of the Emergency Situation and the beginning of the trading restart period, the ESO in cooperation with the EMO shall submit to the WEM Participants and the Commission the calculations on services actually provided by WEM Participants and the price of electricity actually delivered (purchased) during the Emergency Situation according to Provision 15 of the WEM Rules.
17. Within 3 business days from receiving the calculation from the EMO as described in Provision 16 of the WEM Rules, the Commission and the WEM Participants shall submit to the EMO their conclusions in writing. If the parties agree with the calculation results, the EMO shall upload them to the MMS, while in case of disagreements and disputes regarding calculations, the WEM Participants shall be guided by the procedures defined in the WEM Rules.

CHAPTER 5. WEM PARTICIPANTS' RESPONSIBILITY, DISPUTE (DISAGREEMENT) RESOLUTION

18. The WEM Participant shall bear responsibility for non-fulfillment or inadequate fulfillment of the provisions of the WEM Rules in procedures defined by the Law, WEM Rules, and WEM Contract.
19. The WEM Participant shall not be responsible for violations defined in the WEM Rules if they happened due to force majeure circumstances.
20. In terms of the WEM Rules, any circumstance or event (after-effect of that event) that led (may lead) to non-fulfillment or inadequate fulfillment of obligations defined by WEM Rules, and at the same

time is characterized by features stated below, is considered a force majeure situation:

1) The event is out of the control of a party affected by the force majeure.
2) The party affected by force majeure undertook all possible actions and efforts (including precautional, alternative, legally defined) to prevent, weaken, eliminate, or avoid the influence of those circumstances (after-effects);

21. In terms of the WEM Rules, force majeure includes, but is not limited to the following situations:
    1) Natural and man-made calamities; epidemics; acts of God (including floods, earthquakes, hurricanes, tornados, thunderstorms, heavy rains with lightning, snowstorms, and landslides); nuclear, chemical, or biological contamination; strikes; and public disorder;
    2) Rebellions, terroristic acts, wars, invasions, armed conflict, actions of foreign enemies, and blockade, which take place on or involve the territory of the RoA and could not be reasonably predicted;
    3) An act, activity, or inactivity of a state and municipal agency or other authorized body, due to which no permission or right was issued or extended to facilitate fulfillment of obligations, or due to which fulfillment of obligations was hindered, on condition that the WEM Participant acted in compliance with RoA legislation.
22. Where a force majeure situation arises, the affected party shall notify the other party about such circumstances within 10 days after it is reported on or after being impacted by those circumstances. The party that failed to notify the other party shall bear the risks associated with the negative impacts of non-notification.
    22.1. Provision 21 of the WEM Rules shall not restrict the WEM Participant's right to apply to the Commission if extraordinary and unavoidable circumstances other than those described above occur, requesting that they be recognized as force majeure as well, on the condition that they satisfy the requirements of this Chapter.
23. Where a dispute (disagreement) arises between the WEM Participants, the parties shall resolve it through negotiations.
24. The EMO and the ESO shall facilitate alternative dispute resolution within the framework of their jurisdictions.
25. If a dispute (disagreement) is not resolved by the parties, any party may apply to the Commission requesting that it resolve the dispute within its jurisdiction or may file a suit at a competent court, unless the parties have agreed to submit their dispute to arbitration.

SECTION 2. WEM PARTICIPANTS AND WEM CONTRACT

CHAPTER 6. WEM TRADE PARTICIPANTS

26. The electricity trade in the WEM among the WEM Trade Participants shall be conducted based on Transactions signed according to the WEM Rules.
27. The Generators shall be classified in the WEM into the following groups:
    1) Generators operating under Public-Private Partnership (hereinafter: PPP) contracts (hereinafter: IPP plants);
    2) Hydropower plants and plants operating with other renewable energy sources (wind, solar, geothermal, and biomass) under 30 MW capacity, except for IPP plants, with the Power Purchase Guarantee as provided for by the Law (hereinafter: REPP plants);
    3) Generators subject to tariff regulation, except for IPP plants, REPP plants, and the Balancing Service Providing Generator (hereinafter: RPP plants);
    4) Generators operating in competitive conditions (hereinafter: CPP plants), including:
        a) Thermal power plants;
        b) Combined heat and power generation (cogeneration) plants;
        c) Plants with an expired term for power purchase guarantee provided by the Law or by the PPP;
        d) IPP plants, which according to the PPP are eligible to operate under competitive conditions.
    5) Balancing Service Providing Generator under an electricity generation license (hereinafter: BSP).
28. According to the Law, its license, the WEM Rules, and the WEM Contract, a Generator shall:
    1) Sell electricity to the WEM Trade Participants;
    2) Purchase electricity on the WEM in case of failure to fulfill its contractual obligations using its own generation of electricity;
    3) Export electricity.
29. According to the Law, its license, the WEM Rules, and the WEM Contract, the Universal Supplier shall:
    1) Purchase electricity from REPP plants, IPP plants, APPs, and other WEM Trade Participants;
    2) Import electricity;
    3) Sell the surplus of electricity to WEM Trade Participants.
30. According to the Law, its license, the WEM Rules, and the WEM Contract, a Supplier shall:
    1) Purchase electricity from WEM Trade Participants, except for REPP plants, IPP plants, and APPs having signed a contract with the Universal Supplier as defined in the REM Rules;
    2) Import electricity;
    3) Sell the surplus of electricity to WEM Trade Participants.
31. According to its licenses, the WEM Rules, and the WEM Contract, the BSP shall:
    1) Sell electricity on the regulated component of the Bilateral Contracts Market (hereinafter: RC) at quantities defined and prices regulated by the Commission;
    2) Purchase and sell electricity in cases defined by the WEM Rules;
    3) Purchase electricity in the WEM in case of failure to fulfill its contractual obligations using its own generation;
    4) Export and import electricity.
32. The rights defined as per sub-Provisions 2 and 4 of Provision 31 of the WEM Rules may be exercised by the BSP on condition of priority fulfillment of obligations under sub-Provision 1 of Provision 31 and Provision 43 of the WEM Rules.
33. According to the Law, its license, the WEM Rules, and the WEM Contract, an entity involved in wholesale electricity trade (hereinafter: Trader) shall:
    1) Purchase electricity from WEM Trade Participants at non-regulated prices, except for REPPs, IPP Plants, and APPs that have signed a contract with the Universal Supplier as defined in the REM Rules;
    2) Import electricity;

3) Sell electricity;
4) Export electricity.

34. According to the Law, the WEM Rules, and the WEM Contract, to meet its own needs, a Qualified Customer shall:
    1) Purchase electricity in the WEM;
    2) Import electricity;
    3) Sell the surplus of electricity to WEM Trade Participants.
35. To acquire the status of a Qualified Customer, the customer (except for the residential customers) shall meet the following requirements:
    1) Be connected to the Transmission Network or Distribution Network;
    2) Have an electricity Metering Complex corresponding to the requirements of the ETN Code.
36. According to the Law, its license, and the WEM Rules, the Transmitter and Distributor shall purchase electricity on the WEM to cover Transmission Network losses and Distribution Network losses, respectively, and for their own needs. The Universal Supplier instead of the Distributor shall buy electricity on the WEM for that purpose.
37. A REPP shall have the right to consume electricity exclusively to satisfy its own needs at the same or different Metering Points.

CHAPTER 7. WEM SERVICE PROVIDERS

38. According to the WEM Rules, the EMO, ESO, Transmitter, and Distributor as well as the BSP shall provide services to the WEM Participants.
39. The EMO, in compliance with the Law, its license, the WEM Rules, and the WEM Contract, shall:
    1) Perform necessary functions related to the entrance to the MMS and termination of activity of the WEM Participants in the MMS;
    2) Perform necessary functions related to the provision and modification of balance responsibility status of the WEM Trade Participants, as well as the provision of the status of the Qualified Customer;
    3) Operate and maintain the MMS;
    4) Ensure the confidentiality of the information provided by the WEM Participants;
    5) Submit to the MMS the maximum allowed limit for WEM Participants to buy electricity, import electricity, and receive services;
    6) Acting as a beneficiary, submit a written claim to the bank issuing a guarantee for the payment of a sum of money with the guarantee by indicating the bank account number to which the money is subject to transfer;
    7) Return the bank guarantee to the issuing bank, indicating the waiver of its rights to it;
    8) Through the MMS, register the WEM Participants' Orders and Transactions;
    9) Through the MMS, coordinate the normal operation of the DAM, including DAM clearing;
    10) Through the MMS, record the quantities of electricity purchased and sold by WEM Trade Participants;
    11) Through the MMS, calculate imbalances in the BALM;
    12) Through the MMS, except for the Transactions signed in the Non-Regulated Component of the Bilateral Contracts Market (hereinafter: NRC), prepare the statement of charges to be paid for electricity as well as services provided in the WEM by the WEM Participants and submit it for WEM Participants' approval;
    13) Coordinate the cross-border trade of electricity;
    14) Coordinate Commercial Metering in the WEM;
    15) Perform other functions necessary to ensure normal and efficient operation of the WEM.
40. The ESO, in compliance with the Law, its license, the WEM Rules, the ETN Code, and the WEM Contract, shall:
    1) Prepare the electricity system balance;

2) Ensure the secure and reliable operation of the electricity system;
3) Evaluate the system reliability and security indicators based on the Transaction allocation module;
4) Offer WEM Trade Participants with the status of BRPI, BRPA, and BRPG the opportunity to review the Transactions allocation and provide the WEM Trade Participants with its version of the Transactions allocation with reasonable justifications;
5) Manage the provision of System Services;
6) Forecast the losses at the Transmission Network and notify the EMO and the Transmitter;
7) Issue Dispatch Instructions to the BSP for balancing the supply and demand of the TD;
8) In the event of Emergency Situations declared by the ESO, issue Dispatch Instructions to the WEM Participants;
9) Coordinate the cross-border trade of electricity;
10) Ensure the confidentiality of the information provided by the WEM Participants;
11) Perform other functions necessary to ensure secure and reliable operation of the electricity system.

41. The Transmitter, in compliance with the Law, its license, the WEM Rules, and the WEM Contract, shall:
1) Provide transmission services to the WEM Trade Participants;
2) Ensure uninterrupted operation of Metering Complexes that are the property of the Transmission Network.
3) Perform other functions arising from the provision of electricity transmission service.

42. The Distributor, in compliance with the Law, its license, the WEM Rules, and the WEM Contract, shall:
1) Provide distribution services to the WEM Trade Participants;
2) Register Metering Complex data of the WEM Participants connected to the Distribution Network, including Commercial meters and Control meter readings;
3) Ensure the completeness of and availability of EMO access to the registered data through the real-time Automated Data Acquisition System (hereinafter: DAS), MMS, or other available software packages;
4) Perform other functions arising from the provision of electricity distribution service.

43. The BSP, in compliance with the licenses and the WEM Rules, shall provide Balancing Services by purchasing/selling electricity at the BALM, as required for such a purpose.

44. Services provided in the WEM shall be paid by the buyer at whose Metering Points the electricity was metered. In case of export or transit of electricity, the WEM services are paid by the WEM Participant that exports or transits electricity. Services provided in the WEM shall be paid at tariffs approved by the Commission, as follows:
1) For transmission, ESO, and EMO services, if they are connected to the Transmission Network or Generator;
2) For transmission, ESO and EMO services, and distribution services as required by the REM Rules, if they are connected concurrently to the Transmission and Distribution Networks;
3) For transmission, ESO and EMO services, and distribution services as required by the REM Rules, if they are connected to the Distribution Network.

CHAPTER 8. WEM PARTICIPANTS' BALANCING RESPONSIBILITY

45. Within the context of the WEM Rules, the WEM Trade Participant may trade electricity and use WEM services if:
1) It has chosen the type of WEM balancing responsibility according to Provision 46 of the WEM Rules;
2) Its Metering Complex is located at the Boundary point and meets the requirements as per the ETN Code;
3) In case of assuming the status of BRPI, BRPA, or BRPG, it has provided the bank guarantee in compliance with the requirements of Provision 64 and Chapter 30 of the WEM Rules, and the

Universal Supplier, according to the requirements of Chapter 31 of the WEM Rules, has provided funds securing a guarantee of payments.

46. The responsibility for balancing in the WEM may be undertaken in the following ways:
    1) According to Provision 48 of the WEM Rules, the WEM Trade Participant has assumed the status of an independent balance responsible party (hereinafter: BRPI);
    2) According to Provision 49 of the WEM Rules, the WEM Trade Participant has joined the other participant's balancing group, authorizing the latter to bear its balancing responsibility (hereinafter: BRPA),
    3) According to Provision 50 of the WEM Rules, the WEM Trade Participant has joined the other participant's balancing group by authorizing the latter to trade electricity in the WEM on behalf of itself, to undertake the balancing responsibility and pay for services (hereinafter: BRPP),
    4) According to Provision 51 of the WEM Rules, the WEM Trade Participant has assumed the responsibility for imbalances of other WEM Trade Participants or has formed a balancing group (hereinafter: BRPG).
47. The WEM Trade Participant may have only one status at a time out of the aforementioned BRPI, BRPA, BRPP, and BRPG statuses. The WEM Trade Participant may be concurrently involved only in one WEM Trade Participant's balancing group that has acquired BRPG status.
48. The WEM Trade Participant shall be eligible to assume BRPI status and be responsible for its own imbalances in the WEM. If a WEM Trade Participant with BRPI status has more than one Metering Point, then the imbalances shall be considered based on the total number of Metering Points. A WEM Trade Participant with BRPI status may refuse from that status in the case that it assumes BRPA, BRPP, or BRPG status. The RPPs and the Transmitter, in terms of Transactions for the sale/purchase of electricity in the WEM, shall mandatorily have BRPI status and have no right to refuse that status.
49. A WEM Trade Participant shall have the right to obtain BRPA status and to authorize another WEM Trade Participant to bear its balancing responsibility if the latter has BRPG status. The cost of imbalances caused by a WEM Trade Participant with BRPA status and of services resulting from those imbalances shall be charged to the participant with BRPG status, which has assumed the given responsibility. The BRPA may shift its balancing responsibility to another BRPG or refuse the BRPA status if it assumes BRPI, BRPG, or BRPP status.
50. A WEM Trade Participant shall have the right to obtain BRPP status and to be involved in the balancing group of a WEM Participant with BRPG status. The entire responsibility for imbalances in the WEM caused by a WEM Participant with BRPP status shall be undertaken by the participant that involved the latter in its balancing group. The BRPP may authorize another BRPG to trade electricity in the WEM on its behalf and to bear its balancing responsibility or to refuse BRPP status if it assumes BRPI, BRPG, or BRPA status. Traders shall have no right to acquire BRPP status. The following WEM Trade Participants shall mandatorily have BRPP status and have no right to refuse that status:
    1) Distributor
    2) IPP plants
    3) REPP plants.
51. A WEM Trade Participant shall have the right to form a balancing group and assume BRPG status by involving therein WEM Trade Participants with BRPA or BRPP status, whereas Suppliers and Traders may involve APPs. The WEM Trade Participant with BRPG status shall be responsible for imbalances caused by WEM Trade Participants with both BRPA status and BRPP status involved in its balancing group and by APPs. The following WEM Trade Participants shall mandatorily have BRPG status and have no right to refuse that status:
    1) Universal Supplier

2) Suppliers
3) BSP.

52. The relationship between WEM Trade Participants with BRPG status and WEM Trade Participants with BRPA status and BRPP status involved in the balancing group of the latter shall not be regulated, except for the Universal Supplier and participants involved in its balancing group.
53. The following limitations shall be set for the balancing group of a WEM Trade Participant:
    1) A Qualified Customer that has acquired or intends to acquire BRPP status may not be involved in the balancing group of a Qualified Customer with the BRPG status,
    2) A CPP that has acquired or intends to acquire BRPP status may not be involved in the balancing group of a CPP with BRPG status,
    3) An APP may not be involved in the balancing group of a Qualified Customer or CPP with BRPG status.
54. The Universal Supplier and the Supplier shall mandatorily involve the following participants in their balancing group and take joint responsibility for imbalances caused by the latter:
    1) For the Universal Supplier – the Customer that has signed a supply contract with the Universal Supplier, the IPP and REPP plants, APPs (under APP-Distributor electricity exchange agreements) with BRPP status and a signed contract with the Universal Supplier, all plants under commissioning and testing, as well as the Distributor,
    2) For the Supplier – the Customers that have signed a supply contract with the Supplier.
55. A WEM Trade Participant with BRPG status, except for the Universal Supplier, Suppliers, and BSP shall have the right to terminate the activity of a balancing group with the intention to acquire BRPI, BRPP, or BRPA status; it may also remove WEM Trade Participants with BRPP or BRPA status from the balancing group.
56. The balancing responsibility status of the WEM Trade Participant as mentioned in Provision 46 of the WEM Rules shall change or a participant shall involve in another balancing group according to Provisions 70-72 of the WEM Rules. During each change of status or involvement in another balancing group, the terms and conditions for the provision of the given status during MMS registration, as well as those defined in this Chapter, shall apply.

CHAPTER 9. WEM CONTRACT

57. For participation in the WEM, participants shall sign the WEM Contract. The WEM Contract shall be concluded between the WEM Service Providers and the WEM Trade Participants.
58. The WEM Contract is deemed to be a contract of adhesion (offer) in terms of Article 444 of the RoA Civil Code, to which the WEM Trade Participants may join in procedures defined by this Chapter.
59. For registration, WEM Service Providers shall submit their offer to the EMO through the MMS and the WEM Trade Participants shall submit their acceptance to join the WEM Contract that complies with the model contract approved by the Commission.
60. For trading electricity in the WEM, the IPP and REPP plants shall sign the following contracts defined by the Commission in addition to the WEM Contract with the Universal Supplier:
    1) Contract on connection of a power plant under construction (reconstruction) to the Distribution Network on delivery of electricity during commissioning and testing works and the sale/purchase of electricity (Electricity Generator – Distributor Contract for a power plant of 30 MW and greater installed capacity with a power purchase guarantee); or
    2) Contract on connection of a power plant under construction (reconstruction) to the Distribution Network on delivery of electricity during commissioning and testing works and the sale/purchase of electricity (Generator – Distributor (Universal Supplier) Contract for a plant under 30 MW installed capacity with a power purchase guarantee).

SECTION 3. REGISTRATION AND CESSATION FROM THE WEM

CHAPTER 10. PROCEDURE FOR REGISTRATION OF WEM PARTICIPANTS AND ACQUISITION OF BALANCING RESPONSIBILITY STATUS

61. To participate in the WEM, a WEM Participant shall file an application for registration in the MMS, submit the documents listed in Provision 63 of the Rules, and fill in the following data:
    1) Name, State registration number (ID card number);
    2) Tax Identification Number (Social Security Number);
    3) Location (Registration) address;
    4) Notification address (if different from the location (registration) address);
    5) Email address;
    6) Phone number;
    7) Bank details;
    8) Quantity and data of MMS users by vested authorities;
    9) Generators shall provide as well:
        a) Power plant location address;
        b) Metering Complex data by Metering Point;
        c) Type of energy carrier used for electricity generation;
        d) Licensed installed capacity;
        e) Minimum technological capacity;
        f) Ramp-up rate;
        g) Ramp-down rate;
        h) Capacity at each Metering point in case more than one Metering point is connected to the electricity network.
    10) Notice of acquisition of the Qualified Customer status. In this case, the following shall be filled in, as well:
        a) Location of the given consumption system;
        b) Metering Complex data by Metering Point;
        c) Electricity Network connection capacity of the consumption system;
        d) Capacity at each Metering Point in case more than one Metering Point is connected to the electricity network.
62. While registering with the MMS, the WEM Participant shall specify its preferable balancing responsibility status: BRPI, BRPA, BRPP, or BRPG. If it assumes BRPA or BRPP status, the WEM Participant shall specify the details of the WEM Trade Participant with BRPG status that will be responsible for its imbalances.
63. While filing the MMS registration application, the WEM Trade Participant shall attach the following:
    1) The ID card, the State registration certificate (for a legal entity), documents verifying MMS users' Authorities, and their electronic signature samples;
    2) Operation license issued by the Commission, and, in case of obtaining Qualified Customer status, the electricity supply contract signed with the Universal Supplier.
    3) For WEM Service Providers, the signed offer to join the WEM Contract for WEM Trade Participants and digitally signed acceptance of offer, which is subject to registration with the EMO according to the WEM Rules;
    4) Written consent of the WEM Trade Participant with BRPG status, in case the participant intends to acquire BRPA or BRPP status;
    5) The scanned copy of the bank guarantee for the acquisition of BRPI, BRPG ,or BRPA status, except for the Universal Supplier, Transmitter, and BSP.
64. Upon submission of the scanned copy of the original bank guarantee through the MMS, the WEM Trade

Participant that has submitted the bank guarantee shall send the original bank guarantee to the EMO by post or as a registered letter with verification of receipt. Requirements of this Provision shall be in effect while providing a new guarantee after expiration of the current bank guarantee, as well as with the purpose of increasing the allowed amount of the guarantee.

65. Within 1 business day from the receipt of the MMS registration application, except for the case provided by Provision 66 of the WEM Rules, the EMO shall check the compliance of data presented during registration with the MMS and data provided in the Acceptance or Offer, as well as the bank guarantee with the requirements of the Law, the WEM Participant License, the Acceptance of the offer to join the WEM Contract, and the WEM Rules.
66. The ESO shall revise the information on technological and/or emergency capacity provided by the Qualified Customer in the acceptance and shall inform the EMO of the results through the MMS within 3 business days. In the case where it receives positive conclusions from the ESO, the EMO shall check the compliance of the data provided by the Qualified Customer during the registration in the MMS within 1 business day, pursuant to Provision 65 of the WEM Rules.
67. Once the submitted data comply with the requirements of this Chapter and, in case of Qualified Customers, the requirements of Provision 35 as well, the EMO shall register the WEM Participant and:
    1) Provide the MMS access token;
    2) Register the Offer of the WEM Service Provider and acceptance in the case of the WEM Trade Participant;
    3) Register accordingly its BRPI, BRPG, BRPA, or BRPP status, specifying the status' activation year, month, day, and time.
    4) Confirm in the MMS the maximum allowed limit for buying electricity, importing electricity, and receiving services for the given WEM Participant depending on the amount of the submitted bank guarantee. The maximum allowed limit is determined by reducing the amount of the bank guarantee by 5 percent,
    5) Inform the Distributor of the Qualified Customer status obtained.
68. Where non-compliance with the acts specified in Provision 65 is revealed in the MMS registration data, within the timeframe specified in the same Provision, the EMO shall reject the registration by providing reasonable grounds for the rejection in writing.
69. If the EMO rejects the WEM Participant's registration, the new application for registration shall be submitted according to Provisions 61 and 64 of the WEM Rules.

CHAPTER 11. PROCEDURES ON CHANGING AND TERMINATING BALANCING RESPONSIBILITY STATUS

70. At least 10 days prior to the change, in the case of intending to change its balancing responsibility status defined in Provision 46 of the WEM Rules, or at least 25 days prior, in the case of intending to terminate the balancing group activity, a WEM Trade Participant shall submit an application to the EMO through the MMS specifying its preferred balancing responsibility status and the date to assume that status. If the WEM Trade Participant wants to assume BRPP or BRPA status or wants to join a balancing group of another WEM Trade Participant with BRPG status, then it shall attach to its application the written consent of the WEM Trade Participant with BRPG status and to whose balancing group the given participant intends to join.
71. Within 3 business days from receipt of the application mentioned in Provision 70 of the WEM Rules, the EMO shall check its compliance with the requirements of Chapter 8 of the WEM Rules and if no discrepancies are revealed, it shall confirm the new balancing responsibility status of the WEM Trade Participant starting the day specified in the application; where discrepancies are revealed, it shall reject the application, providing reasonable arguments, and notify the applicant through the MMS. In cases where:
    1) The WEM Trade Participant applied to be involved in the balancing group of another WEM Trade

Participant with BRPG status or applied with a request to change its balancing responsibility status within a currently active balancing group, then:

a) Within 2 business days after checking the compliance of the application with the requirements defined in the WEM Rules, the EMO shall, through the MMS, submit the application for the approval of the WEM Trade Participant with BRPG status to whose balancing group the given applicant wishes to join, or in whose balancing group the involved applicant wishes to change its balancing responsibility status;

b) Within 2 business days from receipt of the EMO's notification, the WEM Trade Participant with BRPG status shall approve the involvement of the applicant in its balancing group or the change of its status within the given group or shall reject the request;

c) Within 1 business day after receipt of the answer of the WEM Trade Participant with BRPG status, the EMO shall, from the date specified in his/her application, remove the applicant from the current balancing group and include him/her in the new group or change his/her balancing responsibility status by informing the applicant, the WEM Trade Participant with BRPG status of the current balancing group, as well as the WEM Trade Participant with BRPG status of the new balancing group,

2) The WEM Trade Participant with BRPG status wishes to acquire another balancing responsibility status, the EMO, within 2 business days after having checked the compliance of the application with the requirements defined by the WEM Rules, shall inform the participants involved in the given balancing group through the MMS and, from the date specified in the application, shall terminate the activity of the group and provide the applicant the status mentioned in the application.

72. In case the balancing group terminates its activity and the WEM trade participant included in that group does not assume any other balancing responsibility status or become involved in another balancing group in accordance with this Chapter of the WEM Rules upon receipt of the notice of termination of group activity, then his/her activity in the WEM shall be ceased pursuant to Paragraph (b) of sub-Provision 2 of Provision 73.

CHAPTER 12. PROCEDURE FOR CESSATION OF WEM PARTICIPATION

73. The cessation of a WEM Participant's market participation shall be implemented in the following manner:

1) Upon the initiative of the WEM Participant, except for WEM Service Providers, RPP plants, BSP and the Universal Supplier, by submitting a written application to the EMO at least 10 days prior to the cessation and at least 25 days in the case of a WEM Trade Participant with BRPG status, specifying the year, month, day, and time of the cessation;

2) Upon the EMO's initiative:

a) If the WEM Participant license has been terminated (expired) or the status has been lost;

b) If the WEM Participant failed to choose another balancing responsibility status or join another balancing group according to Chapter 11 of the WEM Rules.

74. A WEM Trade Participant may apply for the cessation of participation in the WEM on condition that:

1) All the obligations undertaken within the framework of the WEM are fulfilled;

2) All the payments provided for by the WEM Rules are paid.

75. In case of cessation of participation in the WEM according to the procedures defined by Paragraph a of sub-Provision 2 of Provision 73 of the WEM Rules, the activities of the given WEM Participant shall be terminated on the day the corresponding resolution of the Commission on license validity expiration or termination of the license enters into force, unless another date is defined by the resolution.

76. In case of cessation as per Paragraph b of sub-Provision 2 of Provision 73 of the WEM Rules, the activity of the given WEM Participant shall be terminated on the day of termination of the balancing group activity according to sub-Provision 2 of Provision 71 of the WEM Rules.

77. Within 5 business days after receipt of the WEM Trade Participant's application, the EMO shall inform the given Participant of its approval of the application if it complies with the requirements specified in Provisions 74 of these Rules, or, in case of non-compliance, inform the Participant of the rejection of the application, specifying the basis for rejection.

78. If the EMO approves the application of the WEM Trade Participant for cessation from the WEM:

1) The WEM Contract with the given WEM Trade Participant shall be considered terminated;
2) Taking into consideration that the generating plant and/or consumption system of the WEM Trade Participant is connected to the Transmission or Distribution Network, the EMO shall inform the latter 5 business days in advance through the MMS about the disconnection of the given participant from the Transmission or Distribution Network, respectively, specifying the year, month, day, and time of the disconnection. If the given participant has acquired the status of a consumer in the Retail Market, then the REM Rules shall apply;
3) In case of a bank guarantee, the EMO, as a beneficiary, indicating its waiver of the rights to it, shall return it to the WEM Trade Participant;
4) If the application has been submitted by a WEM Trade Participant with BRPG status, then the EMO shall terminate its balancing group activity and, at least 20 business days prior, shall inform the WEM Trade Participants involved in that balancing group, specifying the year, month, day, and time of the termination of activity. The balancing responsibility status of these participants shall be changed in accordance with the requirements of Provision 72 of the WEM Rules;
5) If the application has been submitted by a WEM Trade Participant with BRPP or BRPA status, then the EMO shall inform the WEM Trade Participant with BRPG of the balancing group in which the given participant was involved at least 5 business days before the cessation day, specifying the year, month, day, and time of the cessation.

SECTION 4. MMS MODULES AND WEM PARTICIPANT PROFILE

CHAPTER 13. MODULES OF THE MARKET MANAGEMENT SYSTEM SOFTWARE

79. The MMS is designed to ensure operation of the WEM, including electronic communications and trade in different segments of the WEM, conclusion of Transactions, and implementation of calculations.
80. Each WEM Participant shall access the MMS using the token provided by the EMO.
81. The tokens shall be delivered by hand based on the delivery-acceptance act, 4 free-of-charge tokens per Participant, except for REPP plants, for which 2 tokens are provided free of charge. Additional tokens shall be provided by the EMO, subject to payment of 50,000 AMD (value-added tax, or VAT, included).
82. Within 2 business days after the receipt of the application for additional tokens and if a payment verification document is presented, the EMO shall provide the required quantity of tokens to the given Participant, and if no payment document is presented, the EMO shall reject the application.
83. The MMS shall comprise specifications that will be able to ensure:
    1) Uninterrupted and reliable operation of the MMS;
    2) User's two-factor authentication and activity validation through a password generating device and password generating software;
    3) Communication between the WEM Participants;
    4) Use of documents certified by electronic signature;
    5) Issuance and registration of electronic invoices notified and paid;
    6) Data compliance verification and notifications of potential inadequacies for the Orders submitted to different segments of the WEM;
    7) Verification of Transactions in progress in different WEM segments and all Bids as to their being secured by guarantees, and in case the guarantee amount is insufficient, automatic restriction of the Participant's right to bid;
    8) Data integrity and removal protection for information recorded in the MMS;
    9) Protection from unauthorized third-party access;
    10) Automatic application of allowable limits for submission of Orders and conclusion of Transactions by fixing the amount stated in the bank guarantee;
    11) Availability of a backup system, which is based on an individual electronic platform, highly secured, and compatible with the MMS main platform, to be activated in case of malfunction of the MMS main platform or temporary failure of system operation.
84. The MMS shall include at least the following platforms:
    1) Users Database and Management platform;
    2) System Forecast platform;
        a) Annual Adequacy Forecast module;
        b) Availability and Dispatch Information Management module;
    3) Bilateral Contracts Management platform;
    4) Day-Ahead Market Management platform;
    5) BALM Management and Imbalances Settlement platform;
    6) Transaction Management platform comprising:
        a) Transactions allocation module,
        b) Signed Transactions module.
    7) Financial Operations Platform comprising:
        a) Financial guarantees management module;
        b) Invoices module per WEM segments, components, Trading periods, Transactions, Transaction Parties, payments, and liabilities, as well as Metering Points.
    8) Information and communication platform:
        a) Notifications and Inquiries module;

b) Information and analysis module;
c) MMS Users support module.

85. The WEM Trade Participant has right of access to the MMS platforms and modules that are directly relevant to him/her.
86. The EMO shall be responsible for the operation, safety, maintenance, and control of the MMS.
87. The EMO and the ESO, within the framework of their jurisdictions, shall be responsible for the confidentiality of the information recorded in the MMS.

CHAPTER 14. WEM PARTICIPANT'S VIRTUAL ELECTRONIC CARD (E-CARD)

88. The WEM Participant's virtual e-card shall be included in the MMS Users Database platform.
89. The virtual e-card of the WEM Participant registered with the MMS shall contain information defined in this Chapter. The WEM Participant shall be required to notify EMO about any inaccuracies or changes in the data recorded on their virtual cards.
90. The general profile of the WEM Participant's virtual e-card shall contain the following data:
    1) Name, State registration number (ID card number);
    2) Tax Identification Number (Social Security Number);
    3) Location (Registration) address;
    4) Notification address (if different from the location (registration) address);
    5) Email address;
    6) Phone number;
    7) Bank details;
    8) Licenses, if required by law;
    9) Balance responsibility status in the WEM acquired in accordance with Provision 46 of the WEM Rules;
    10) Quantity and data of MMS users by vested authorities;
    11) For a WEM service provider, the signed offer for the WEM contract, and for a WEM Trade Participant, an electronic copy of the acceptance of the WEM Contract and the functions reserved for the latter in the WEM;
    12) WEM segments and components where the WEM Participant is entitled to act.
91. For a Generator, the virtual e-card shall also contain the following information:
    1) Power plant location address;
    2) Metering Complex data by Metering Point;
    3) Type of energy carrier used for electricity generation;
    4) Licensed installed capacity;
    5) Minimum technological capacity;
    6) Ramp-up rate;
    7) Ramp-down rate;
    8) Capacity at each Metering Point if more than one Metering Point is connected to the electricity network.
92. For a Qualified Customer, the electronic virtual card shall also contain the following information:
    1) Location of the given consumption system;
    2) Metering Complex data by Metering Point;
    3) Electricity network capacity of the consumption system;
    4) Capacity at each Metering Point if more than one Metering Point is connected to the electricity network.

CHAPTER 15. WEM PARTICIPANT'S ELECTRONIC ACCOUNT

93. The WEM Participant's electronic account consists of the following sub-accounts:
    1) Seller sub-account;
    2) Buyer sub-account;
    3) Importer sub-account;
    4) Exporter sub-account;
    5) Balancing sub-account.
94. In addition to the sub-accounts defined in Provision 93 of the WEM Rules, the Universal Supplier shall have also the Universal Supplier sub-account.
95. Each sub-account of the WEM Participant's electronic account shall include data on transactions carried out by the latter for each Trading Period per segment and component of the WEM, including:
    1) Quantity of electricity, for the purchase or sale of which the WEM Participant concluded Transactions, by segment and component of the WEM;
    2) Confirmations made by the EMO and the ESO verifying the conclusion of Transactions for the cases defined by the WEM Rules;
    3) Quantity of electricity that, according to Metering Complex records, has been actually purchased and sold by the WEM Participant;
    4) Hourly differences between the electricity quantities stated in the signed Transactions and those actually traded by the WEM Participant;
    5) Prices for hourly differences of electricity quantities that were stated in Transactions and those that were actually traded by the WEM Participant and their cumulative sum;
    6) Guaranteed allowed limits and residual values of the WEM Trade Participants with BRPI, BRPA, or BRPG status to purchase and/or import electricity and receive services.

SECTION 5. ELECTRICITY SYSTEM ANNUAL ADEQUACY FORECAST

CHAPTER 16. ANNUAL ADEQUACY FORECAST OF THE ELECTRICITY SYSTEM

96. The Annual Adequacy Forecast of the electricity system aims to:
    1) Assess the ability to meet the domestic market demand, demonstrated appropriately by the hourly balances of supply and demand for all steady-state regimes in which the electricity system may operate under the normal operation;
    2) Cover the domestic market demand by dispatching all available resources on a least-cost principle, ensuring reliability and security of the system, as well as hourly schedules of the GEAM and AMIR interconnections;
    3) Develop generation schedules for RPP plants, subject to approval by the Commission in accordance with Provision 108 of the WEM Rules;
    4) Assess availability of reserve capacities for balancing;
    5) Assess the feasibility of cross-border (including transit) flows.
97. The ESO shall develop the AAF based on its own forecasts and estimates of the demand and supply of the RoA electricity system, available information on the capability of interconnection transmission lines, as well as data inputs from the WEM Participants and competent authorities of the other countries' electricity systems.
98. By October 1 of each year, the WEM Participants mentioned in Provision 99 of these WEM Rules shall submit to the ESO the hourly schedules of their forecasted supply and consumption to the Distribution and/or Transmission Networks for all 12 months of the next calendar year.
99. The WEM Participants shall provide the following information to the ESO:
    1) The EMO shall provide the forecasted hourly import and export schedules on an annual basis, including transit;
    2) Generators (except for REPP and IPP plants) shall provide:
        a) Generation hourly schedules, own consumption needs, and losses for each individual unit separately (if the plant consists of several units) on an annual basis. Moreover, generation schedules for HPPs with annual or seasonal regulation reservoirs shall be based on the average historical amount of annual generation for HPPs. Generation schedules for HPPs with multiannual regulation reservoirs shall be based on the guaranteed amount of electricity generation, taking into account the hydrological situation forecasted at the start of the year and the reserve water resources in the reservoir of the HPPs under consideration. The irrigation regime forecast for the period covered by the AAF is coordinated with the RoA state authorized body. River natural flow forecasts for the period covered by the AAF shall take into account the multiannual trends of hydrological situation changes and the forecasts of the meteorological service;
        b) Relevant justifications when an application in accordance with the ETN Code is presented for the modification of technical characteristics during the observed period by the AAF.
    3) The Universal Supplier shall provide:
        a) Hourly load schedules on an annual basis for all connection nodes in the WEM for its customers;
        b) Generation schedules for REPP and IPP plants, as well as the forecasted amount of electricity delivered to the Distribution Network by the APPs (based on electricity exchange between the APP and Distributor);
    4) The distributor shall provide the forecasts of losses and own needs of the Distribution Network, which is comprised in accordance with the EDN Code;
    5) Suppliers shall present the hourly load schedules for all connection nodes in the WEM on an annual basis;

6) Each Qualified Customer shall present the Load schedules for all connection nodes in the WEM on an annual basis;

7) Traders shall provide the forecasts of generation schedules for their contracted APPs, if any.

100. To submit to the ESO the information mentioned in sub-Provision 3 of Provision 99 of the WEM Rules, each year by September 1, the Universal Supplier shall receive the following:

1) IPP plants shall submit the information mentioned in sub-Provision 2 of Provision 99 of the WEM Rules;

2) Customers whose annual demand was equal to or greater than 1 million kWh for a previous calendar year, except Qualified Customers shall submit their load schedules.

101. The ESO shall take into account the forecasted electricity generation of the new plants and the capacity of the out-of-operation plants during the observed AAF period.

CHAPTER 17. ANNUAL ADEQUACY FORECAST VERIFICATION

102. By October 20 of each year, the ESO shall submit through the MMS to each WEM Participant the draft AAF. Within 3 business days, the WEM Participants shall approve the Draft or provide to the ESO their objections. The ESO may accept or reject each suggestion on the draft AAF to ensure system reliability and security indicators. If a suggestion is rejected, the ESO shall inform the WEM Participant through the MMS by providing reasonable justifications. The ESO shall provide all the suggestions, rejections, and justifications to the body authorized by the RoA Government and the Commission.

103. By November 1 of each year, the ESO shall be obliged to coordinate the AAF with the state authorized body and present it to the Commission and the WEM Participants.

104. Within 10 business days from receipt of the AAF, the Commission may require from the ESO clarifications and/or revisions to the AAFif it does not comply with the requirements of the Law or legal acts of the Commission or contains unsubstantiated assessments.

105. The ESO shall provide necessary clarifications not later than 5 business days in cases defined in Provision 104 of the WEM Rules.

106. By November 15, the WEM Participants may submit to the Commission their suggestions in response to the AAF clarification.

107. Based on Provisions 96 and 104 of these WEM Rules, the Commission shall inform the ESO of its final position by December 15. Within 2 business days from receipt of the Commission's position, ESO shall approve and publish the AAF.

108. By December 15, the Commission shall approve:

1) The mandatory amount of electricity for sale in the RC by RPP plants;

2) Available and Contractual capacities of IPP plants if provided by the PPP contract.

SECTION 6. ELECTRICITY TRADE IN THE WEM

CHAPTER 18. WEM STRUCTURE

109. The WEM comprises the following market segments:
    1) Bilateral Contracts Market;
    2) Day-Ahead Market;
    3) Balancing Market.
110. The Bilateral Contracts Market consists of the following components:
    1) Long-term contracts component;
    2) Regulated component;
    3) Non-regulated component.
111. Electricity from all plants during the commissioning and testing works that was delivered during that period to the Transmission or Distribution Networks shall be sold exclusively to the Universal Supplier under the terms stipulated by the Commission.
112. For trade on the NRC, the rights of APPs on electricity exchange with the Universal Supplier arising from the REM Rules shall be deemed terminated.

CHAPTER 19. TRADE OF ELECTRICITY IN THE LONG-TERM CONTRACTS COMPONENT OF THE BILATERAL CONTRACTS MARKET

113. Electricity trade in the Long-Term Contracts Component of the Bilateral Contracts Market (hereinafter: LC) shall be carried out between IPP plants and REPP plants on the one hand and the Universal Supplier on the other hand, as well as IPP plants and the BSP in cases provided for by the PPP Agreement.
114. The relationship between IPP plants and the BSP shall be regulated according to the contract signed in the LC. The BSP shall be obliged to sell the electricity quantity stated in the provisions of the contract with IPP plants signed in the LC to the Universal Supplier.
115. IPP and REPP plants shall not be eligible to sell electricity in other WEM segments or components. The prices of electricity sold to the Universal Supplier shall be regulated by the Commission.
116. The ESO shall be eligible to issue Dispatch Instructions to IPP plants that signed contracts with the Universal Supplier in the WEM LC to reduce to the minimum the electricity purchase expenses required to satisfy the needs of the Universal Supplier and its customers. In such cases, the ESO shall take into consideration the priority obligation of the Universal Supplier to buy electricity from IPPs and REPPs.
117. The sale/purchase of capacities of IPP plants shall be carried out in the LC and shall include capacities ordered by the ESO according to the ETN Code.

CHAPTER 20. ELECTRICITY TRADE IN THE REGULATED COMPONENT OF THE BILATERAL CONTRACTS MARKET

118. Trade of electricity in the RC shall be carried out between RPP plants and the BSP on the one hand, and the Universal Supplier, Suppliers, and Qualified Customers, as well as the Transmitter on the other hand. Traders and CPP plants shall not trade in the RC.
119. Trade of electricity in the RC shall be based on tariffs defined by the Commission and on monthly quantities of electricity mandatory for sale in the RC approved by the Commission in accordance with Provision 108 of the WEM Rules.
120. Within the period from the 15th day to the 20th day of each month, the Universal Supplier, Suppliers, and Qualified Customers as well as the Transmitter shall submit to the EMO their bids for electricity through the MMS, subject to purchase the next month in the RC, which shall contain information

on the electricity quantity in the form of hourly load schedules. In cases when the Universal Supplier, Suppliers, Qualified Customers, as well as the Transmitter submit bids electricity after the expiration of the period specified in this Provision, the latter shall not participate in the monthly electricity trade of the RC.

121. The electricity quantity specified in the Bid shall not exceed the average quantity of electricity consumed at the Metering Point during the same period over the last three years. Where data on the quantity of consumed electricity for the last three years is missing, then:
    1) Data on the previous two years or, if not available, on the previous one year shall be taken into account;
    2) For new customers connected to the electricity Transmission Network or Distribution Network, monthly data on the forecasted volume of electricity consumption specified in the documents attached to the Connection Application and in the connection contract shall be taken into account.
122. A WEM Trade Participant that participates in the RC shall have the right to change or withdraw its bid before the date specified in Provision 120 of the WEM Rules.
123. Within 1 business day after the date specified in Provision 120 of the WEM Rules, the EMO shall distribute through the MMS the quantity of electricity subject to mandatory sale by RPP plants and BSP in the RC in the month defined by the Commission among the Universal Supplier, Suppliers, Qualified Customers, and Transmitter that have submitted Bids, accordingly:
    1) Where the cumulative quantity of electricity specified in the bids is more than the quantity of electricity subject to sale by RPP plants within the next month, then the quantity specified in the Bids shall be allocated between participants who submitted the Bids in proportion to the quantities of electricity specified in their Bids;
    2) Where the cumulative quantity of electricity specified in the bids is less than the quantity of electricity subject to sale by RPP plants within the next month, then the bid of each WEM Trade Participant shall be satisfied according to the quantity of electricity specified in the submitted Bid;
    3) Electricity shall be allocated first from generators operating at low tariffs defined by the Commission and then from the generators operating at higher tariffs;
    4) Mathematical rounding shall be applied when sold electricity is allocated between buyers, but if the sold or purchased electricity exceeds the quantity specified in the Orders as a result, mathematical rounding shall be applied to the deficit.
124. Within 1 business day after the electricity quantities subject to mandatory sale in the RC are allocated among the WEM Trade Participants according to Provision 123 of the WEM Rules, the EMO shall record in the corresponding sub-accounts of the WEM Participants' virtual e-cards the data on electricity quantities subject to delivery and on amounts subject to payment in accordance with transactions registered.
125. Electricity subject to mandatory sale in the RC by RPP plants and the BSP but not demanded shall be included in the amount of electricity to be sold in the DAM.
126. Electricity subject to mandatory sale in the RC by RPP plants and the BSP but not demanded may be sold in the NRC and may be exported after the closure of the DAM, according to Chapter 27 of the WEM Rules.
127. Where deviations from the Transactions signed in the RC are revealed, the EMO and the WEM Participants, as parties to the Transaction, shall be guided by the regulations defined in Chapter 25 and Chapter 26 of the WEM Rules.

CHAPTER 21. ELECTRICITY TRADE IN THE NON-REGULATED COMPONENT OF THE BILATERAL CONTRACTS MARKET

128. Electricity trade in the NRC shall be conducted between the CPP plants, the BSP, APPs, Traders, the Universal Supplier, Suppliers, Qualified Customers, the Transmitter and, in cases defined in Provision 132 of the WEM Rules, the RPP plants as well.

129. Electricity trade in the NRC shall be concluded based on Transactions signed between the NRC participants. The participants in the NRC shall be required to notify the ESO and the EMO of the quantity of electricity subject to trade under these Transactions according to Provision 130 of the WEM Rules.
130. In order for the Transaction on purchase of electricity in the NRC to become effective, no later than 1 business day after signing the Transaction (or, in cases when the Transaction implies trading within the TD, no later than by 1 day prior to Trading Day [hereinafter: TD-1] at 16:59), the Participants who have signed the Transaction shall be obliged to confirm through the MMS the information on the quantity of electricity purchased and sold. The ESO and the EMO shall be automatically informed through the MMS of the Transactions signed.
131. A transaction for the purchase of electricity in the NRC may be amended or terminated by the WEM Participants who concluded the Transaction at any time, and in cases when the Transaction implies trading within the TD, no later than by TD-1 at 16:59. Amendment or termination of the Transaction shall take effect after the parties to the Transaction confirm it through the MMS. The ESO and the EMO shall be automatically informed through the MMS of the Transactions signed.
132. After the publication of the DAM results under the procedures defined by Provision 160, the RPP plants shall have the right to sell electricity not demanded in the DAM to the NRC within the period from 15:30 to 16:59 of TD-1.
133. Once the Transaction signed by the NRC participants is submitted to the EMO in accordance with Provision 130, not more than 1 hour later, the EMO shall:
    1) Register the Transaction in the MMS as a Transaction concluded by parties;
    2) In line with the registered Transaction, record in the corresponding sub-accounts of the Participants' virtuale-cards the data on electricity quantities subject to delivery between the Participants without data on amounts subject to payment.
134. Export and import of electricity from the NRC may be carried out according to Chapter 27 of the WEM Rules.
135. Where deviations from the Transactions signed in the NRC are revealed, the EMO and WEM Participants party to the Transaction shall be guided by the regulations defined in Chapter 25 and Chapter 26 of the WEM Rules.

CHAPTER 22. DAY-AHEAD MARKET

136. Trade of electricity in the DAM shall be carried out by CPP plants, RPP plants, Traders, the Universal Supplier, Suppliers, Qualified Customers, the Transmitter, and the BSP, with regard to electricity that is subject to mandatory sale but not demanded in the RC.
137. Trade of electricity in the DAM shall be carried out on an hourly basis. The electricity quantities subject to sale and purchase and their prices shall be calculated by the MMS in procedures defined by Chapter 23.
138. All DAM activities shall be carried out for the next TD and completed 1 day prior to TD-1, within the periods defined in this Section.
139. Prices of Offers submitted to the DAM by the WEM Participants shall not exceed the maximum BSP price approved by the Commission, and in the case of the RPP plants, to be 20 percent higher than the electricity tariff defined by the Commission or have a negative value. Such Offers shall be rejected by the EMO.
140. DAM Participants may submit the following types of Orders:
    1) Offers – single or stepwise;
    2) Bids – single or stepwise.
141. DAM Orders should include the following information:
    1) For a single Order that proposes one price for electricity purchased or sold in each Trading Period of the TD, the information comprises:
        a) The electricity price expressed in AMD/kWh with an accuracy of up to 2 decimal places;

b) The electricity quantity expressed in kWh.

2) In the case of a single Order without pricing:

a) If it is an Offer, only the quantity of electricity for sale is indicated, with the price equal to zero;

b) If it is a Bid, only the quantity of electricity demanded is indicated, with the price equal to the maximum price defined by the Commission for the provision of Balancing Services.

3) In the case of stepwise Orders, the Order proposes different price-quantity steps over the TD trading period, depending on the quantities subject to sale or purchase. Such a Bid or Offer shall include up to 5 steps, in which the sale price for each successive step shall be higher than the previous one, whereas the purchase price for each successive step shall be lower than the previous one. At the same time, the price-quantity steps in Bids and Offers shall be proposed independently, so that the seller be able to sell and the buyer be able to buy any price-quantity step separately. Bids and Offers shall contain the information specified in the above-mentioned Sub-Provision 1, paragraphs a and b for each proposed step.

142. Export and import of electricity from the DAM shall be carried out according to Chapter 27 of the WEM Rules.

CHAPTER 23. DAM CLEARING RULES

143. For DAM Clearing purposes, all electricity Offers and Bids submitted by the WEM Participants shall be aggregated in order to produce 1 aggregated supply curve and 1 aggregated demand curve for each Trading Period. The processes shall entail adding all offered quantities at each price step to construct the aggregated supply curve and adding all demanded quantities at each price step to construct the aggregated demand curve.

144. If the aggregated supply and the aggregated demand curves for the specific Trading Period intersect, then the Clearing Price for that period, as well as the fully or partially cleared and non-cleared Orders, shall be determined in accordance with Provisions 146 to 151.

145. If the aggregated supply and the aggregated demand curves for the specific Trading Period do not intersect, then the Clearing Price for that period, as well as the fully, partially cleared, and non-cleared Orders, shall be determined in accordance with Provisions 152 to 155.

146. Where there is just one price point and more than one quantity point at which the aggregated supply and demand curves intersect and the quantity of the marginal Offer is equal to the quantity of the marginal Bid, then:

1) The Market Clearing price of the specific Period of the TD is the price at the intercept;

2) An Offer is fully cleared as long as its price is equal to or lower than the Market Clearing Price of the specific Trading Period of the TD;

3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;

4) A Bid is fully cleared as long as its price is equal to or higher than the Market Clearing Price of the specific Trading Period of the TD;

5) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;

6) The cleared market quantity equals the total quantity of the cleared Offers, which also equals the quantity of cleared Bids.

147. Where there is just one point at which the aggregated supply and demand curves intersect and the quantity of the marginal Offer exceeds the quantity of the marginal Bid, then:

1) The Market Clearing price of the specific Period of the TD is the price at the intercept, which is determined by the marginal Offer;

2) An Offer is fully cleared as long as its price is lower than the Market Clearing Price of the specific

Trading Period of the TD;

3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) The marginal Offer shall be partially cleared at the Market Clearing Price of the specific Trading Period of the TD up to the quantity that is cleared by the marginal Bid. Where the marginal Offer is composite, i.e., several Offers with the same price have been received from different WEM Participants, then the residual amount of electricity required to clear the Bids shall be allocated among these Participants in proportion to the quantity indicated in each Offer;
5) A Bid is fully cleared as long as its price is higher than the Market Clearing Price of the specific Trading Period of the TD;
6) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;
7) The cleared market quantity equals the total quantity of the cleared Bids.

148. Where there is one price point and more than one quantity point over which the aggregated supply and demand curves intersect and the quantity of the marginal Offer exceeds the quantity of the marginal Bid, then:
1) The Market Clearing Price of the specific Period of the TD is the price at the intercept;
2) An Offer is fully cleared as long as its price is lower than the Market Clearing Price of the specific Trading Period of the TD;
3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) The marginal Offer shall be partially cleared at the Market Clearing Price of the specific Trading Period of the TD for up to the quantity that is cleared by the marginal Bid. Where the marginal Offer is composite, i.e., several Offers with the same price have been received from different WEM Participants, then the residual amount of electricity required to clear the Bids shall be allocated among these Participants in proportion to the quantity indicated in their Offers;
5) A Bid is fully cleared as long as its price is equal to or higher than the Market Clearing Price of the specific Trading Period of the TD;
6) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;
7) The cleared market quantity equals the total quantity of the cleared Offers.

149. Where there is just one point at which the aggregated supply and demand curves intersect and the quantity of the marginal Bid exceeds the quantity of the marginal Offer, then:
1) The Market Clearing Price of the specific Period of the TD is the price at the intersection point, which is determined by the marginal Bid;
2) An Offer is fully cleared as long as its price is lower than the Market Clearing Price of the specific Trading Period of the TD;
3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) The marginal Bid shall be partially cleared at the Market Clearing Price of the specific Trading Period of the TD for up to the quantity that is covering the marginal Offer. Where the marginal Bid is composite, i.e., several Bids with the same price have been received from different WEM Participants, then the residual amount of electricity required to clear the Offers shall be allocated among these Participants in proportion to the quantity indicated in their Bids;
5) A Bid is fully cleared as long as its price is higher than the Market Clearing Price of the specific Trading Period of the TD;
6) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;

7) The cleared market quantity equals the total quantity of the cleared Offers or step of Offers.

150. Where there is one price point and more than one quantity point over which the aggregated supply and demand curves intersect and the quantity of the marginal Bid exceeds the quantity of the marginal Offer, then:

1) The Market Clearing price of the specific Period of the TD is the price at the intersection points;
2) An Offer is fully cleared as long as its price is equal to or lower than the Market Clearing Price of the specific Trading Period of the TD;
3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) The marginal Bid or a step of the Bid shall be partially cleared at the Market Clearing Price of the specific Trading Period of the TD for up to the quantity that is covering the marginal Offer. Where the marginal Bid is composite, i.e., several Bids with the same price have been received from different WEM Participants, then the residual amount of electricity required to clear the Offers shall be allocated among these Participants in proportion to the quantity indicated in their Bids;
5) A Bid is fully cleared as long as its price is higher than the Market Clearing Price of the specific Trading Period of the TD;
6) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;
7) The cleared market quantity equals the total quantity of the cleared Offers.

151. Where there are more than one price point and one quantity point over which the aggregated supply and demand curves intersect at the point where the quantity of the marginal Bid is equal to the quantity of the marginal Offer then:

1) The Market Clearing price of the specific Period of the Trading is determined by the marginal Offer;
2) An Offer is fully cleared as long as its price is equal to or lower than the Market Clearing Price of the specific Trading Period of the TD;
3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) A Bid is fully cleared as long as its price is higher than the Market Clearing Price of the specific Trading Period of the TD;
5) A Bid shall not be cleared if the price is equal to or lower than the Market Clearing Price of the specific Trading Period of the TD;
6) The cleared market quantity equals the total quantity of the cleared Offers, which also equals the cleared Bids. Offers and Bids submitted by WEM Participants that lead to an increase in the total cleared market quantity will not be cleared regardless of their price.

152. Where the aggregated supply and demand curves do not intersect because the quantity of the marginal Offer is not enough to match any Bid at the indicated Offer price, then an additional zero quantity-price step equal to the corresponding Bid is considered to be the marginal Offer. Following this adjustment, the DAM clearing will be performed in accordance with the following rules:

1) The Market Clearing Price of the specific Period of the TD is the price at the intersection point, which is determined by the marginal Bid;
2) An Offer is fully cleared as long as its price is lower than the Market Clearing Price of the specific Trading Period of the TD;
3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) The marginal Bid shall be partially cleared at the Market Clearing Price of the specific Trading Period of the TD for up to the quantity that covers the marginal Offer. Where the marginal Bid is composite, i.e., several Bids with the same price have been received from different WEM

Participants, then the residual amount of electricity required to clear the Offers shall be allocated among these Participants in proportion to the quantity indicated in their Bids;

5) A Bid is fully cleared as long as its price is higher than the Market Clearing Price of the specific Trading Period of the TD;
6) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;
7) The cleared market quantity equals the total quantity of the cleared Offers.

153. Where the aggregated supply and demand curves do not intersect because the price of the marginal Bid is higher than the price of the marginal Offer and the quantity of the marginal Offer is equal to the quantity of the marginal Bid, then:
1) The Market Clearing price of the specific Period of the TD is determined by the marginal Offer;
2) An Offer is fully cleared as long as its price is equal to or lower than the Market Clearing Price of the specific Trading Period of the TD;
3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) The marginal Offer shall be partially cleared at the Market Clearing Price of the specific Trading Period of the TD for up to the quantity that is covering the marginal Bid. Where the marginal Offer is composite, i.e., several Offers with the same price have been received from different WEM Participants, then the residual amount of electricity required to clear the Bids shall be allocated among these Participants in proportion to the quantity indicated in their Offers;
5) A Bid is fully cleared as long as its price is higher than the Market Clearing Price of the specific Trading Period of the TD;
6) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;
7) The cleared market quantity equals the total quantity of the cleared Offers which also equals the quantity of cleared Bids.

154. Where the aggregated supply and demand curves do not intersect because the price of the marginal Bid is higher than the price of the marginal Offer and the quantity of the marginal Offer exceeds the quantity of the marginal Bid, then:
1) The Market Clearing price of the specific Period of the TD is determined by the marginal Offer;
2) An Offer is fully cleared as long as its price is lower than the Market Clearing Price of the specific Trading Period of the TD;
3) An Offer shall not be cleared if the price is higher than the Market Clearing Price of the specific Trading Period of the TD;
4) The marginal Offer shall be partially cleared at the Market Clearing Price of the specific Trading Period of the TD for up to the quantity that is covering the marginal Bid. Where the marginal Offer is composite, i.e., several Offers with the same price have been received from different WEM Participants, then the residual amount of electricity required to clear the Bids shall be allocated among these Participants in proportion to the quantity indicated in their Offers;
5) A Bid is fully cleared as long as its price is higher than the Market Clearing Price of the specific Trading Period of the TD;
6) A Bid shall not be cleared if the price is lower than the Market Clearing Price of the specific Trading Period of the TD;
7) The cleared market quantity equals the total quantity of the cleared Bids.

155. Where the aggregated supply and demand curves do not intersect because the price of the first Offer is higher than the price of the first Bid, then the EMO shall inform the Participants that the DAM shall not be cleared.

CHAPTER 24. DAM TRANSACTIONS

156. The submission of Orders in the DAM starts at 10:29 in TD-1 and ends at 12:59 in TD-1, which is the DAM Gate Closure Time.
157. The DAM Participants may modify or withdraw the submitted Orders before the DAM Gate Closure Time. The price proposals of DAM Orders made by the WEM Trade Participants in the MMS shall become visible for the EMO only after 14:29 of TD-1.
158. Taking into consideration the electricity prices and quantity specified by Participants in their Orders, the EMO shall validate DAM Orders through the MMS and, before 13:59 of TD-1, shall accept the Order or suggest that the WEM Trade Participant revise the Order, providing reasonable justifications for non-acceptance. Participants that receive a suggestion for revision from the EMO shall be required to submit the final revised Order to the EMO before 14:29 of TD-1.
159. The EMO shall perform the DAM Clearing through the MMS based on the Orders received by 14:30 of TD-1.
160. By 14:59 of TD-1, the EMO shall publish in the MMS and on its official website the DAM Clearing Prices and the summary data on electricity sale/purchase Transactions per Trading Periods of the TD.
161. Electricity sale/purchase Transactions between WEM Trade Participants that submitted Offers and Bids that have been cleared as a result of DAM Clearing shall be deemed concluded from the period specified in Provision 160 of the WEM Rules.
162. The DAM Transactions shall be concluded such that the electricity quantity sold by each WEM Trade Participant on the DAM shall be allocated between buyers in proportion to the amount of electricity purchased per Trading Period of the TD. Moreover, mathematical rounding is applied during the allocation of the amount of electricity between buyers, but if the sold or purchased electricity exceeds the quantity specified in the Orders as a result, mathematical rounding shall be applied to the deficit. When there is electricity surplus sold at the Clearing price in the DAM as a result of the above calculations, the residual amount of the electricity of the WEM Participant who sold a larger amount of electricity and submitted the Offer first shall be allocated by unit between Participants, prioritizing those who sold the larger amount of electricity and submitted an Offer first until the electricity surplus is completely allocated. The same approach is applied in the case of electricity deficit, sold at the Clearing price in the DAM.
163. Before 19:59 of TD-1, the EMO shall register all the executed Transactions of the DAM in the MMS and record in the Participants' virtual e-cards the data the quantity and costs of electricity sold and purchased per TD-1 Trading Period.
164. Where deviations from Transactions signed in the DAM are revealed, the EMO and the parties of the Transaction shall be guided by regulations defined in Chapter 25 and Chapter 26 of the WEM Rules.

CHAPTER 25. BALANCING MARKET

165. Trading of balancing electricity between the BSP on one hand and other WEM Trade Participants with BRPI status and BRPG status on the other hand shall be implemented on the BALM.
166. The BALM shall be a regulated market where Transactions are executed as a result of Imbalance settlement calculations performed by the EMO through the MMS.
167. By 15:29 of TD-1, the BSP shall publish in the MMS the sale price of electricity for the TD for balancing purposes for all Trading Periods if it is lower than the maximum BSP price set by the Commission. The BSP balancing electricity price cannot be more than 20 percent of the DAM Clearing price, if DAM clearing has been done and the price is above zero. Otherwise, the BSP balancing electricity price for TD shall be assumed to be equal to the maximum price defined by the Commission if the BSP has not published the balancing electricity price. The BSP shall be obliged to comply with all dispatch instructions of the ESO on balancing the TD's supply and demand.

168. WEM Trade Participants with BRPI status and BRPG status shall sell electricity surplus and purchase electricity shortages that occur as a result of imbalances from the BSP, in cases and procedures defined by the WEM Rules.

CHAPTER 26. IMBALANCE SETTLEMENT

169. The imbalances shall be calculated by the EMO through the MMS for each WEM Trade Participant with BRPI status and BRPG status for each Trading Period of the TD.
170. By 17:59 of TD-1, each WEM Trade Participant with BRPI, BRPA, and BRPG status, except for the Transmitter, shall submit to the ESO and EMO the quantities of electricity subject to delivery, export, and import, as well as that which is subject to generation and consumption at Metering Points with a capacity of 10 MW or above in all WEM segments during the TD period per all Metering Points and Trading Periods of the TD (hereinafter: Transactions allocation).
171. Per Trading Period, WEM Trade Participants shall submit Transaction allocations that correspond to the technical characteristics included in their virtual e-card, also taking into account information about non-availability.
172. The ESO, based on the Transactions allocation submitted by the WEM Trade Participants with BRPI status and BRPG status, shall evaluate the system reliability and security indicators based on the requirements of the ETN Code. The ESO has the right to offer to review the Transactions allocations of WEM Trade Participants with BRPI status and BRPG status in cases where their offered option does not enable them to ensure system reliability and security indicators and they cannot be regulated in procedures defined by the ETN Code through the BSP.
173. Where the change of a Transactions allocation offered by a WEM Trade Participant with BRPI and/or BRPG status is deemed necessary by the ESO, then by 19:29 of TD-1, the ESO shall submit through MMS to the given participant its suggested Transaction allocation option with relevant justifications. The WEM Trade Participant with BRPI or BRPG status shall be obliged to accept and be guided by the Transaction allocation option offered by the ESO.
174. The net volume of imbalances for each WEM Trade Participant with BRPI or BRPG status shall be calculated by the EMO through the MMS and determined in the following way:
    1) The actual quantity of metered electricity delivered, consumed, exported, or imported shall be determined for the Metering Point of each WEM Trade Participant with BRPI or BRPG status per Trading Period of the TD;
    2) The volume of TD net imbalances for each WEM Trade Participant with BRPI or BRPG status shall be determined by comparing the actual metered data by Trading Periods with the Transactions concluded by the latter, except for sub-Provision 3 of this Provision. Moreover, the calculation of imbalances resulting in the cross-border trade of electricity shall be carried out separately, and the calculated imbalances shall be distributed proportionally among the WEM participants carrying out import and export of electricity in proportion to Transactions on an hourly basis. When calculating imbalances, the minimum unit of measurement is 1 kWh, and smaller units are subject to mathematical rounding.
    3) In case of electricity import and export Transactions, no imbalance is calculated if there are no imbalances arising from the Transactions of the WEM Trade Participant.
175. Payments for imbalances to be assigned to each BRPI or BRPG as appropriate based on the aggregation of their imbalances for each Trading Period in the TD shall be calculated as follows:
    1) When the BRPI- or BRPG-netted imbalance volume during the Trading Period is negative, and as a result of this, the BRPI or BRPG buys electricity from the BSP, then an amount equal to the product of that quantity of electricity and the price defined by the BSP in each Trading Period of the TD as specified in Provision 167 of the WEM Rules shall be debited to the latter's balancing sub-account as an amount to be paid to the BSP;

2) When the BRPI- or BRPG-netted imbalance volume during the Trading Period is positive and as a result of this, the BRPI or BRPG sells electricity to the BSP, then an amount equal to the product of that quantity of electricity and the price corresponding to the lowest tariff for sale set for the WEM RC shall be credited to the latter's balancing sub-account as an amount to be paid by the BSP.

176. The EMO shall conduct and upload records defined by Provision 175 of the WEM Rules to the MMS by 08:59 of the one day after the Trading day (TD+1).

SECTION 7. CROSS-BORDER TRADE, TRANSIT, AND TECHNICAL POWER FLOWS

CHAPTER 27. CROSS-BORDER TRADING

177. Cross-border trade of electricity shall be carried out by concluding a direct contract with a foreign natural person or legal entity on the export of electricity or on the import of electricity to be sold in the WEM or to meet its own demand.

178. Import of electricity shall be carried out by the Universal Supplier, Suppliers, Traders, Qualified Customers, and BSPin the following cases:

1) The Universal Supplier and Suppliers import electricity to meet the electricity demand of WEM participants or customers in their balancing group;

2) Traders import electricity to meet the electricity demand of WEM Participants in their balancing group, as well as to sell it in the NRC and DAM;

3) Qualified Customers may import the electricity to satisfy their demand.

179. Export of electricity shall be carried out by Traders, CPPs, and, if prescribed by the WEM Rules, by the BSP and RPPs in the following cases:

1) Traders, CPPs, RPPs, and the BSP shall export electricity subject to sale in the NRC;

2) Traders shall export electricity subject to sale in the DAM;

3) The BSP may export the electricity purchased from the WEM Participants as a result of imbalances.

180. In order for a Transaction on import or export of electricity to be considered effective, no later than 1 business day after signing the Transaction (or, in cases when the Transaction implies trading within the TD, no later than by TD-1 at 16:59), the WEM Trade Participant who is a party to the Transaction shall be obliged to submit information on the amount of electricity imported or exported on an hourly basis to the ESO and the EMO through the MMS.

181. Transactions on import or export of electricity may be amended or terminated by the WEM Participants who concluded the Transaction at any time, and in cases when the Transaction implies trading within the TD, no later than by TD-1 at 16:59. The WEM Participant shall inform the ESO and the EMO through the MMS of the amendment or termination of the Transaction, providing the approval of the other party to the Transaction.

182. Information on the export and import of electricity shall be included in the Transactions allocation provided in Provision 170 of the WEM Rules.

183. The EMO and the ESO shall coordinate the process of organizing cross-border trade in procedures defined by the WEM Rules.

184. In cases of import of electricity, the seller is deemed to have delivered the purchased electricity to the buyer at the Point of Import.

185. Where deviations from Transactions signed on cross-border trade are revealed, the EMO and the Party to the Transaction shall be guided by regulations defined in Chapter 25 and Chapter 26 of the WEM Rules.

CHAPTER 28. TRANSIT OF ELECTRICITY

186. Transit of electricity shall be performed through the Traders based on the contract signed with the transit client.

187. Electricity transit is considered to be a simultaneous Transaction of import and export of electricity carried out by a Trader and all provisions of the WEM Rules on the import and export of electricity shall apply to it equally. The amount of imported electricity is not taken into account in the payments to the WEM Service Providers stated in Provision 44 of the WEM Rules.

188. Where deviations from Transactions signed on the transit of electricity are revealed, the EMO and the Party to the Transaction shall be guided by regulations defined in Chapter 25 and Chapter 26 of

the WEM Rules.

189. Transit delivery of electricity shall be carried out only if it neither contradicts the interests of domestic consumers, nor reduces reliability and security indicators of the RoA electricity system, nor hinders the fulfillment of obligations undertaken within the framework of already-concluded contracts of the BSP with respect to the AMIR Interconnection.
190. The ESO may terminate transit delivery if the reliability and security indicators of the RoA electricity system are reduced or are under threat of reduction.

CHAPTER 29. TECHNICAL POWER FLOWS

191. Technical power flows shall be carried out exclusively by the BSP through the AMIR Interconnection based on the electricity generation license issued by the Commission and the AMIR technical power flows agreement.
192. The BSP shall sign contracts with the ESO, the EMO, and the Transmitter, as well as the Distributor, if it requires using the Distribution Network as well.
193. To fulfill its obligations, the BSP shall have the right to purchase electricity in WEM in cases provided for by the WEM Rules. Electricity generated at the Vorotan Cascade shall not be purchased for technical power flow exchange through AMIR.
194. The ESO shall coordinate the implementation of technical power flows.
195. The ESO shall be obliged to notify the EMO and the BSP in writing of the commencement, interruption, resumption, or termination of the technical power flows as prescribed in Provision 180 of the WEM Rules.
196. The ESO may terminate technical power flows if reliability and safety indicators of the RoA electricity system are reduced or are under threat of reduction.
197. In Emergency Situations, technical power flows through the AMIR and GEAM Interconnections shall be carried out by the BSP based on relevant contracts.

SECTION 8. WEM PAYMENTS GUARANTEES

CHAPTER 30. PAYMENTS GUARANTEE MECHANISM

198. To buy, import or export electricity and receive services on the WEM, the WEM Trade Participants, excluding the Universal Supplier, Generators, Transmitter, and the BSP, shall provide to the EMO a bank guarantee issued by any commercial bank operating in the Republic of Armenia, in procedures prescribed in this Chapter, Provision 64 of the WEM Rules, and Annex 1 to the WEM Rules.

199. The bank that presented the guarantee upon the request of the WEM Trade Participant (principal) shall accept liability in writing before the creditor of the principal that, in case of non-fulfillment or inadequate fulfillment by the principal of its liabilities under Transactions, following the written application of the EMO acting as a beneficiary in an undisputable manner, a certain amount will be transferred to a corresponding bank account specified by the EMO within the relevant limits of the guarantee amount.

200. For the bank guarantee:
   1) The effective period shall not be less than 45 days;
   2) The defined amount shall not be less than 5 million AMD.

201. When submitting an Order in the RC and DAM, the available residual amount of the WEM Trade Participant's bank guarantee in the MMS shall be reduced as follows:
   1) In the case of submitting Bids in the RC—by 150 percent of the cost calculated as a product of the quantity of electricity stated in the Bid and the highest tariff defined for RPP plants participating in the RC;
   2) In the case of submitting Bids in the DAM—by the cost of electricity calculated as a product of the quantity of electricity stated in the Bid and the maximum tariff defined by the Commission for balancing services.

202. The available residual amount of the WEM Participant's bank guarantee mentioned in Provision 201 of the WEM Rules as a result of the Transaction concluded in the RC and DAM shall be adjusted in the MMS as follows:
   1) By an amount equal to the cost of electricity purchased under the Transaction;
   2) By an amount equal to the cost of the ESO service, which is determined as a product of the quantity of electricity purchased under the given Transaction and the tariff defined by the Commission for the ESO service;
   3) By an amount equal to the cost of the EMO service, which is determined as a product of the quantity of electricity purchased under the given Transaction and the tariff defined by the Commission for the EMO services;
   4) By an amount equal to the cost of the Transmitter's service, which is determined as a product of the quantity of electricity purchased under the given Transaction and the tariff defined by the Commission for transmission services;
   5) By an amount equal to the cost of the Distributor's service, which is determined as a product of the quantity of electricity purchased under the given Transaction and the average weighted cost of distribution service for the given WEM Trade Participant actually formed in the previous month. If no distribution service was provided to the given WEM Trade Participant, the bank guarantee amount shall be determined as a product of the quantity of electricity purchased under the given Transaction and the highest tariff defined by the Commission for the provision of distribution services to the Participant at Metering Points on the distribution network;
   6) For the cost of balancing service which is equal to the product of a twentieth of electricity quantity purchased under the Transaction and the maximum tariff defined for balancing services.

203. The available residual amount of the WEM Participant's bank guarantee as a result of the Transaction concluded in NRC shall be adjusted in the MMS as follows:
   1) By the sum of monthly costs of services determined in accordance with sub-Provisions 2–5 of

Provision 202 of the WEM Rules, except for electricity Import Transactions, for which the guarantee amount shall not be reduced;

2) By the amount of the monthly cost of Balancing services determined in accordance with sub-Provision 6 of Provision 202, except for electricity Transit, Export, and Import Transactions;

3) In the case of electricity Transit, Export, and Import Transactions, by the amount of the monthly cost of electricity calculated as a product of electricity purchased under the given Transaction and the maximum tariff defined by the Commission for balancing services.

204. Once the settlement of imbalances of the NRC, DAM, and RC is completed as described in Provision 176 of the WEM Rules, the reduced amount of the WEM Participant's bank guarantee (mentioned in Provisions 202 and 203 of the WEM Rules) shall be adjusted in the MMS before 09:59 of TD+1 in the following manner:

1) By an amount equal to the cost of the service actually rendered by ESO, which is determined as a product of the quantity of electricity actually purchased for the TD and the tariff defined by the Commission for ESO service;

2) By an amount equal to the cost of the service actually rendered by the EMO, which is determined as a product of the quantity of electricity actually purchased for the TD and the tariff defined by the Commission for EMO services;

3) By an amount equal to the cost of the service actually rendered by the Transmitter, which is determined as a product of the quantity of electricity actually purchased for the TD and the tariff defined by the Commission for transmission services;

4) By an amount equal to the cost of the service actually rendered by the Distributor, which is determined by the cost of the distribution service formed as a product of the quantity of electricity purchased for the TD and the distribution service tariff for the given connection point of the WEM Trade Participant; if the WEM Trade Participant is connected to the different voltage levels of the distribution network, then the bank guarantee shall be reduced by an amount equal to the sum of service costs formed as a result of the product of electricity passed through the given voltage level and the distribution service tariff defined for the given voltage level;

5) By an amount equal to the cost of the balancing service actually rendered, which is determined by the cost of electricity actually purchased from the BSP for the TD.

205. The allowed bank guarantee limit of the WEM Trade Participant shall comprise the total sum of costs of Transactions already signed but not paid for and services obtained, as well as new Transactions to be signed and services to be rendered.

206. Upon expiration of the maximum allowed limit, the WEM Participant shall be deprived of the right to submit new Orders and conclude new Transactions. If the given WEM Participant has made all the payments to the sellers for electricity purchased, imported, or exported and services provided under the Transaction, then the bank guarantee presented by that WEM Participant to the EMO shall be considered not to be encumbered by liabilities that are already paid, and the given WEM Participant shall regain the right to submit new Orders and conclude new Transactions. If the WEM Participant makes complete or partial payments to the seller within the framework of its Transactions, the given Participant shall inform the EMO within 1 business day by presenting a proof of payment through the MMS.

CHAPTER 31. PROCEDURES FOR MAKING PAYMENTS FROM THE SPECIAL ACCOUNT (ACCOUNTS) OF THE UNIVERSAL SUPPLIER AND USING THE GUARANTEED AMOUNT

207. The Universal Supplier shall ensure guaranteed payments to Generators with 30 MW and over of installed capacity and WEM Service Providers for electricity purchased for the LC, DAM, and BALM and in the RC thraccount special account (accounts) and a bank guarantee agreed upon with the Commission in the required guaranteed amount as a supplementary means to secure the payment of

debts accumulated by the end of the previous month. The Guarantee shall not be less than 10 percent of the total amount charged for the previous year's average monthly purchase of electricity (capacity) and for services provided by WEM Service Providers **(except for the services provided by the Distributor).** The choice of the banks servicing the special account (accounts) shall be coordinated with the Commission.

208. The special account (accounts) servicing contracts and modifications to these contracts and the Guarantee shall be agreed upon with the Commission in advance.

209. The special account (accounts) funds shall be managed in compliance with WEM Rules and the Universal Supplier License.

210. Payments in cash made by customers for consumed electricity shall be accepted by commercial banks operating in the territory of the RoA and by legal entities holding a license for the provision of payment and settlement services (hereinafter: payment and settlement organizations), in compliance with the contracts signed by the Universal Supplier with the banks and payment and settlement organizations. According to these contracts, the payments collected from the customers for the consumed electricity by the banks and the payment and settlement organizations shall be transferred to the special account (accounts) in one banking day, except for the amounts collected by Haypost Closed Joint Stock Company, which shall be transferred to the special account (accounts) within 1 banking day in Yerevan, 2 banking days in urban communities, and up to 5 banking days in rural communities. The payments collected from the customers for the electricity consumed, except for the Special Account (accounts), cannot be transferred to another bank account, as stated in the contracts signed between the Universal Supplier and banks or payment and settlement organizations. The contracts and further modifications thereto shall be submitted to the Commission for approval.

211. In the case of a bank transfer for the electricity consumed, the customer shall transfer funds only to the banking account mentioned in the invoicing documents issued by the Universal Supplier, and the Universal Supplier shall mention only one of the Special Accounts or attached technical accounts (subaccounts) in the invoicing documents submitted to the customers.

212. The Universal Supplier's payments for the electricity purchased and services provided to WEM Participants can be made only through the Special Account (accounts) based on the Universal Supplier's payment orders.

213. If the Universal Supplier fails to make payments by the time defined in the Contracts, the Generators with 30 MW and over of installed capacity and WEM services providers **(except for the Distributor)** in the LC, DAM, BALM, and RC may apply to the bank that provided the Guarantee to have their requirements met under that Guarantee. The guarantee-issuing bank shall review the submitted claims and issue a Resolution within 5 business days. If the funds under the Guarantee are insufficient to cover the amounts claimed and the amounts to be covered by the Guarantee-issuing bank, the Universal Supplier shall transfer the deficient amount to the Special Account (accounts) and pay to the Participants that have submitted claims to the guarantee-issuing bank the amount sufficient enough to cover the claims and meet the coverage deficiency within the 5 business days required for revision of claims and issuance of the resolution. If the claims are satisfied by the guarantee-issuing bank, the Universal Supplier shall submit a new Guarantee to the Commission for approval within 10 working days.

214. Starting on the 5th day of each month, the total amounts deposited into the Special Account (accounts) shall be deemed to be pledged in favor of Generators with 30 MW and over of installed capacity and WEM Service Providers **(except for the Distributor)** in the LC, DAM, and BALM segments and in the RC as means to secure the payment of actual debts accumulated by the end of the previous month. This should be stated in the pledge agreements between the Universal Supplier and the above entities. Generators with installed capacity under 30 MW; other sellers acting in the LC, DAM, and BALM and in the RC; and service providers other than WEM Service Providers shall not sign pledge agreements with the Universal Supplier. The pledge agreement, as well as modifications and changes thereto, shall be coordinated with the Commission. The amounts deposited into the Special Account (accounts) shall also be used for making payments for electricity purchased by the Universal Supplier from other entities in order to sell it on the domestic market. The pledge shall be terminated after the

Universal Supplier fulfills all financial liabilities available at the end of the previous month. Upon completion of the mentioned function, the Universal Supplier may dispose of the amounts available in the Special Account (accounts) and transfer them to its current accounts only.

215. Only the amounts collected from the customers for electricity consumed or amounts transferred exclusively from the current accounts of the Universal Supplier can be deposited into the Special Account (accounts). Funds from the Special Account (accounts) can only be used for making payments for electricity purchased and services provided in the LC, DAM, and BALM segments and in the RC, or, if the collateral is terminated as mentioned in Provision 214 of the WEM Rules, they can be transferred exclusively to the current accounts of the Universal Supplier.
216. The procedure in Provision 215 of the WEM Rules shall be stated in the Special Account (accounts) service contract (contracts).
217. Each month, the Universal Supplier shall provide the Special Account (accounts) transaction statement to the Commission, in compliance with the forms set by the Commission.

SECTION 9. METERING OF ELECTRICITY AND INVOICING

CHAPTER 32. EMO RESPONSIBILITY FOR COMMERCIAL METERING

218. This Section shall define regulations and relationships associated with electricity metering in the WEM.

219. Commercial metering in the WEM, calculation of inevitable technological losses during actual regimes of the Transmission Network, and metering of actual losses of electricity in the Transmission Network shall be implemented by the EMO.

220. The EMO shall implement Commercial metering in the WEM for Boundary Points of WEM Participants located on the Transmission and Distribution Networks based on data collected from Metering Complexes installed at those Boundary Points. In case of failure of commercial meters, the EMO shall implement Commercial metering based on the data received from control Metering Complexes specified in the WEM Contract.

221. The EMO shall be liable for the reliability of the data it has submitted, in procedures defined in RoA law.

CHAPTER 33. METERING DATA COLLECTION AND PERIODICITY

222. Collection of data from the metering points shall be implemented by the EMO through the DAS. The minimum unit of the metering data is 1 kWh, and smaller units are subject to mathematical rounding.

223. For the purposes of metering data collection, the EMO shall ensure the following:
   1) Operational condition of the DAS and related infrastructure;
   2) Collection of data being transferred from Metering Complexes to the system-level server;
   3) Reflection of metering data in the MMS in real time for all Trading periods of the TD.

224. WEM Participants shall ensure free access to Metering Complexes registered in the DAS and the possibility of unhampered collection of data by the EMO, as well as ensure the working condition of equipment and devices used for data transmission and communication.

CHAPTER 34. METERING OF ELECTRICITY ONTHE GENERATOR SIDE

225. Electricity delivered by a Generator shall be metered for each plant separately. The Commercial Metering Complex shall be installed in compliance with the requirements defined in the ETN Code.

226. The EMO shall be obligated to meter electricity delivered or consumed by the Generator at:
   1) The Generator-Transmitter point;
   2) The Generator-Distributor Boundary point;
   3) The Generator-Customer Boundary points.

227. Commercial metering of the IPP's Contractual capacity in the WEM shall be performed by the EMO according to the contract signed between the Universal Supplier and the IPP. The Contractual capacities shall be subject to payment if a two-part tariff with an electricity rate and a monthly capacity charge is established for IPP plants. If the information provided by the ESO on the IPP's available capacities for the Trading Period contains different data on actual available capacities, then their average weighted capacity shall be recorded as the one to be paid for.

228. Reduction of the IPP's available capacity shall be considered a Contract violation and shall not be subject to payment.

CHAPTER 35. METERING OF ELECTRICITY ON THE TRANSMITTER AND DISTRIBUTOR SIDE

229. Metering of electricity transmitted by the Transmitter shall be implemented at the Generator-Transmitter, Transmitter-Qualified Customer, and Generator-Distributor Boundary Points, as well as at the Import and Export points; and for the Distributor, at the Distributor-WEM Trade Participant Boundary Point.

230. The EMO shall be obligated to register the following data with regard to the Transmitter and the Distributor:
   1) Electricity imported by the WEM Participants at the Import point;
   2) Electricity delivered by the WEM Participants at the Export point;
   3) Electricity delivered to the Distributor at the Transmitter-Distributor Boundary Point;
   4) Electricity delivered to the WEM Participants at the Distributor-WEM Participant Boundary Point.

CHAPTER 36. SPECIFIC METERING RECONCILIATION CASES

231. For metering data verification, the EMO shall prepare electricity balances of WEM Trade Participants for the balancing group (or groups) formed by Metering Complexes included in the DAS according to the ETN Code.

232. In the case that the actual established balance exceeds the limit values of the average statistical data for the last year or the allowable imbalance limit values, then:
   1) The EMO shall be obliged to inform the parties to the Transaction of the sudden change in the metered levels and offer to find out the reasons for the sudden changes in the metered value.
   2) The parties to the Transaction, with the involvement of the EMO, shall inspect the balance group (or groups) of Metering Complexes registered in the DAS, and, if failures are detected in the Metering Complexes, shall prepare a corresponding statement.
   3) The EMO shall make recalculations when there is a statement about a failure of commercial Metering Complexes.
   4) If no failure is detected in the balancing group of Commercial Metering Complexes and their connection circuits, the deviation of the actual imbalance value from the average statistical data (if the actual imbalance value does not exceed the allowable imbalance limit value of the given Balancing group) is deemed to be acceptable due to the agreed changes of regime, and recalculations shall not be performed.
   5) If the actual imbalance value exceeds the allowable imbalance limit value, but a failure of the Metering Complexes and its connection circuits is not detected as a result of the inspection, the party managing the Metering Complexes shall perform an ad-hoc inspection of Commercial meters as well as current and potential transformers, prepare relevant protocols, and replace the Metering Complexes, if necessary. The cited reports are the basis for drawing up a recalculation statement.
   6) Recalculation shall be performed based on the data received from the control meters. Recalculation results shall be included in the payment documents of the next month after the failure is detected.

233. The allowable imbalance limit shall be determined by the EMO in compliance with the methodology approved by the Commission's Resolution No. 60 of November 19, 2001 "On calculation of unavoidable losses of electricity at 110 kV and higher electric networks."

CHAPTER 37. CALCULATION OF LOSSES AT THE TRANSMISSION NETWORK

234. By the 10th day of each month, the EMO shall be obligated to submit to the Transmitter information in writing about actual losses of metered electricity in the Transmission Network for the previous month, as well as to publish the information in the MMS.

235. Before the 15th day of the next month, the EMO shall calculate the inevitable technological losses caused by actual regimes of operation in the Transmission Network for the given Trading Period, according to the methodology approved by the Commission's Resolution No. 60 of November 19, 2001 "On the calculation of unavoidable losses of electricity at 110 kV and higher electric networks" and publish it in the MMS.

CHAPTER 38. STATEMENT OF CHARGES

236. Within the first 2 business days of each month, based on information recorded in the electronic accounts of WEM Participants (in accordance with Chapter 15 of the WEM Rules), the EMO shall prepare a statement of charges to be paid for electricity and provided services and submit them to the WEM Participants for confirmation.
237. Charges to be paid for electricity and provided services shall be calculated in AMD with an accuracy of up to 2 decimal places through mathematical rounding.
238. If the WEM Participants have no objections to the charges for electricity and provided services, they shall confirm the statement of charges presented by the EMO within 2 business days after receiving the statement.
239. Within 2 business days after confirming the statement of charges, the WEM Participants shall prepare and submit to other parties the statement of charges on electricity delivered or purchased or services provided.
240. The WEM Participant who received the statement of charges shall, within 1 business day after the day of receipt, confirm the statement of charges for electricity delivered to him/her or purchased by and for the services provided to him/her or provided by him/her, and within 3 business days shall make respective payments, except for the Universal Supplier. The Universal Supplier shall make the payments by the 25th day of each month.

SECTION 10. MONITORING OF THE WEM

CHAPTER 39. DATA COLLECTION REQUIREMENTS

241. The ESO and the EMO shall be responsible for collecting data provided for by this Section and for publishing them on the official websites as appropriate, making them permanently available.

242. The ESO shall collect and publish the following data:

1) Information on the electricity system load per Trading Period, to be published based on the information provided by the EMO;
2) The electricity system load forecast per Trading Period, to be published at least 14 hours before the DAM Gate Closure and be updated afterward every 2 hours on a rolling basis;
3) Week-, month-, and year-ahead aggregated electricity system load forecasts, to be published based on the forecast data; year-ahead System Load Forecasts, to be published every week;
4) Information relating to the unavailability of the transmission network, to be published no later than 1 hour after the change in availability;
5) Information relating to congestion management measures, if any;
6) Forecast of total generation per Trading Period;
7) Information related to the unavailability of Generating Units;
8) The Renewable Energy Sources (RES) Forecast per Trading Period of the TD. Such forecasts should be made publicly available for every Trading Period of the TD by 08:59 of TD-1.

243. The EMO shall collect and publish the actual delivery per Trading Period (per technology, where data is available).

CHAPTER 40. MONITORING OF THE DAM

244. The EMO shall collect and publish the following data on the DAM:

1) Information on the electricity system load per Trading Period;
2) Volume of electricity trade in the DAM;
3) DAM Clearing Price per Trading Period of the TD;
4) Imbalance Settlement Prices per Trading Period defined in accordance with Chapter 26 of the WEM Rules;
5) Total Imbalance quantities per Trading Period.

SECTION 11. TRANSITIONAL PROVISIONS

245. Before February 1, 2023:

1) RPPs and plants whose legally defined purchase guarantees have expired, as well as those that have no purchase guarantee, shall be mandatorily involved in the Universal Supplier's Balancing Group by obtaining binding BRPP status, according to Provision 54 of the WEM Rules. The Universal Supplier shall be responsible for any imbalances caused by RPPs and plants with expired purchase guarantees, as well as those that have no purchase guarantee that are included in its Balancing Group;

2) RPPs, as well as TPPs with a capacity exceeding 30 MW, for which the Commission has set a capacity fee, taking into account the importance of maintaining the Electricity System reliability and safety indicators during the transition phase at levels required by the System Operator, shall also participate in the LC, as prescribed in Provision 113 of the WEM Rules. The Universal Supplier shall buy electricity (capacity) ordered by its Customers from the mentioned plants at the tariffs set by the Commission. In cases provided for under this Provision, the following shall be applied for thermal power plants with a capacity exceeding 30 MW:

   a) In regard to capacity that was not ordered for Customers of the Universal Supplier, the regulations established for Traders shall be applied according to the WEM Rules, subject to priority Transactions concluded as a Trader;

   b) In regard to capacity ordered for Customers of the Universal Supplier, the regulations established for IPPs shall be applied, at the same time reducing the capacity to be paid for by the Universal Supplier according to Provision 227 of the WEM Rules by the amount calculated as follows:

$$\Delta P_{TPP} = \frac{P_O * \sum_{i=1}^{T} P_{NRi}}{P_{TPP} * T},$$

Where:

ΔP_{TPP} – the amount of capacity (MW) subject to reduction from the capacity to be paid for by the Universal Supplier to the TPP exceeding 30 MW

P_O – the amount of capacity (MW) ordered for Customers of the Universal Supplier from the TPPs exceeding 30 MW

P_{NRi} – the amount of capacity (MW) to be traded by the TPPs exceeding 30 MW at hour *i* and at non-regulated prices

P_{TPP} – the total installed capacity of all aggregates (units) of the TPP exceeding 30 MW to be involved in the electricity trade at non-regulated prices for the volumes ordered for Customers of the Universal Supplier (MW)

T – the number of hours of the settlement month

3) The RC defined in Chapter 20 of the WEM Rules shall not operate;

4) According to Provision 113 of the WEM Rules, the plants whose purchase guarantees have expired, as well as those that have no purchase guarantee, shall also participate in LC trading. The Universal Supplier shall buy electricity from the mentioned plants at the minimum price set for the Generators providing Balancing Services. This Provision shall not restrict the right of plants whose guarantee purchase has expired, as well as those that have no purchase guarantee, to participate in WEM trading as a Trader, losing the right to sell electricity to the Universal Supplier in the LC and leaving the Balancing Group of the Universal Supplier;

5) According to Provision 136 of the WEM Rules, RPP plants shall not participate in DAM trading.

ANNEX 1. BANK GUARANTEE FORM

(To be filled in a bank form)

20

BANK GUARANTEE No. _____

By this guarantee (hereinafter, referred to as the Guarantee), _____(hereinafter, referred to as the Guarantor), upon request of _____(hereinafter, referred to as the Principal), is unconditionally committed to paying a monetary amount of up to _____ (hereinafter, the Guarantee Amount) to _____(hereinafter, referred to as the Beneficiary), following the written claim of the latter (hereinafter, referred to as the Claim) for non-compliance or inadequate compliance of the Principal with the liabilities arising from the _____ contract (hereinafter, referred to as the Contract) signed on_ __20__ between the Principal and the Beneficiary, pursuant to the following conditions:

1. The Guarantee shall be a security for adequate fulfillment by the Principal of its liabilities under the Contract;
2. The Guarantee shall be valid from __ ___ 20___ until ___ ___20___ inclusive;
3. The following documents shall be enclosed with the Claim:
   a. _____,
   b. _____.
4. Within a maximum of _ business days after the receipt of the Claim and documents enclosed, the Guarantor is committed to discussing the Claim and documents enclosed, in order to check their compliance with the terms of the Guarantee.
5. The Guarantee Amount shall be reduced by the amount paid by the Guarantor according to the Claim.
6. The Beneficiary's right of claim for the payment of the Guarantee Amount arising from the Guarantee may be assigned to the other entity upon the written consent of the Guarantor.
7. Relations associated with the Guarantee shall be regulated by the Legislation of the Republic of Armenia.

Authorized person/Signature

REPUBLIC OF ARMENIA WHOLESALE ELECTRICITY MARKET CONTRACT (OFFER)

The Electricity Market Operator (EMO), Electricity System Operator (ESO), Transmitter, Distributor, Balancing Services Providing Generator (hereinafter, together defined as Wholesale Electricity Market Services Providers) on one side, and all Wholesale Electricity Market Trade Participants on the other side, mutually called Parties, being guided by the Republic of Armenia Law on Energy (Law), other laws of the Republic of Armenia, the WEM Trading Rules and Electricity Market Transmission Network Code (hereinafter, together defined as the Rules) and other legal acts of the Commission, signed this contract on the following:

CHAPTER 1. SUBJECT OF CONTRACT

1. Subject to the terms of this contract and the Rules:
   1) For trading of electricity in the WEM, the WEM Trade Participants shall be obliged to acquire balancing responsibility status as well as to conclude and execute Transactions in procedures defined by the Rules;
   2) The EMO undertakes to coordinate WEM operations, including WEM Participants' registration and adherence to this Contract ;
   3) The ESO, the EMO, the Distributor, and the Transmitter undertake to provide, respectively, the services of the electricity system operator, electricity market operator, electricity distribution, and electricity transmission, and the WEM Participant undertakes to pay for the provided services;
   4) The Generator providing balancing services (BSP) undertakes to provide such services by trading electricity required for balancing in the Balancing Market (BALM).

CHAPTER 2. RIGHTS AND OBLIGATIONS OF THE PARTIES

2. The WEM Trade Participants, in accordance with the Law, the License, the Rules, and this Contract, shall be responsible for:
   1) Registering in the Market Management System (MMS) and acquiring balancing responsibility status;
   2) In order to buy, to import electricity as well as to receive services, the WEM Trade Participants, excluding the Universal Supplier, Generators, and the Transmitter, shall provide to the EMO a bank guarantee;
   3) Endorsing the requirement of the EMO to receive monetary compensation in case of a violation of the obligations assumed under this Contract and Transactions by another WEM Participant within the framework of the bank guarantee provided by the violating Participant;
   4) Presenting their Transactions allocation to the ESO and the EMO and, in case of comments by the ESO, approving and applying the Transactions allocation option offered by the latter within the TD;
   5) Executing Transactions on electricity trading;
   6) Paying the WEM services providers for the provided services;
   7) Selling electricity surpluses and purchase electricity shortages from the BSP that occur as a result of imbalances;
   8) Adopting and approving the statement of charges to be paid for electricity and provided services prepared by the EMO as well as billing documents submitted by the WEM Participants;
   9) Acting in accordance with the dispatch instructions issued by the ESO in the event of Emergency Situations;

10) Selling electricity in Emergency Situations at the maximum price defined by the Commission for the BSP, except for cases provided for by legal acts;

11) Ensuring the fulfillment of other obligations prescribed by the specified legal acts.

3. The WEM Trade Participants, in accordance with the Law, the License, the Rules, and this Contract, have the right to:

1) Demand that parties to a Transaction in the WEM pay for electricity sold based on the Transaction;

2) Export and import electricity in cases envisaged by the specified legal acts;

3) Terminate activity in the WEM, except for the Generators subject to tariff regulation (except for Generators defined in the Rules), as well as the Universal Supplier, Transmitter, and Distributor;

4) Exercise other rights prescribed by the specified legal acts.

4. The EMO, in accordance with the Law, the License, the Rules, and this Contract, shall be responsible for:

1) Enabling entrance to the MMS and termination of activity of the WEM Participants in the MMS;

2) Enabling the provision and modification of balance responsibility status of the WEM Trade Participants, as well as enabling the provision of Qualified Customer status;

3) Operating and maintaining the MMS;

4) Ensuring the confidentiality of the information provided by the WEM Participants;

5) Submitting to the MMS the maximum allowed limits for buying electricity, importing electricity, and receiving services for the WEM Participants;

6) Acting as a beneficiary, submitting a written claim to the bank issuing the guarantee to pay a sum of money with the guarantee by indicating the bank account number to which the money is subject to transfer;

7) Returning the bank guarantee to the WEM Trade Participant, waiving rights to it;

8) Registering the WEM Participants' Orders and Transactions through the MMS;

9) Coordinating the normal operation of the Day Ahead Market (DAM), including DAM clearing through the MMS;

10) Recording the quantities of electricity purchased and sold by WEM Trade Participants through the MMS;

11) Calculating imbalances in the BALM through the MMS;

12) Through the MMS (except for Transactions signed in the Non-Regulated Component of the Bilateral Contracts Market), preparing the statement of charges to be paid for electricity as well as services provided in the WEM by the WEM Participants and submitting them for the WEM Participants' approval;

13) Coordinating the cross-border trade of electricity;

14) Coordinating Commercial Metering in the WEM;

15) Ensuring normal and efficient operation of the WEM.

5. The EMO, in accordance with the Law, the License, the Rules, and this Contract, has the right to:

1) Require the Parties to pay for the services provided;

2) Refuse the registration of a WEM Trade Participant in the MMS, the application of a WEM Trade Participant for cessation from the WEM, the granting of balancing responsibility status to a WEM Participant or the modification of said status, or the granting of Qualified Customer status;

3) Ensure fulfillment of other functions arising from the provision of the electricity market operator services.

6. The ESO, in accordance with the Law, the License, the Rules, and this Contract, shall be responsible for:

1) Preparing the electricity system balance;

2) Ensuring the secure and reliable operation of the electricity system;

3) Evaluating system reliability and security indicators based on the transactions allocation module;

4) Managing the provision of System services;

5) Forecasting losses from the Transmission Network and notifying the EMO and the Transmitter;

6) Coordinating the cross-border trade of electricity;
7) Ensuring the confidentiality of the information provided by the WEM Participants;
8) Performing other functions necessary to ensure the secure and reliable operation of the electricity system.

7. The ESO, in accordance with the Law, the License, the Rules, and this Contract, has a right to:
1) Require the Parties to pay for the services provided;
2) Issue dispatch instructions to the BSP for balancing the supply and demand of the TD;
3) Offer to a WEM Trade Participant that has assumed the status of a BRPI, BRPA, or BRPG to review the Transactions allocation and provide the latter with its version of the Transactions allocation with reasonable justifications;
4) Issue dispatch instructions to the WEM Participants in the event of Emergency Situations declared by the ESO;
5) Ensure fulfillment of other functions arising from the provision of electricity system operation services.

8. The Transmitter, in accordance with the Law, the License, the Rules, and this Contract, shall be responsible for:
1) Providing transmission services to the WEM Trade Participants;
2) Ensuring the uninterrupted operation of the Metering Complexes in the Transmission Network;
3) Performing other functions arising from the provision of electricity transmission service.

9. The Transmitter, in accordance with the Law, the License, the Rules, and this Contract, has a right to:
1) Procure electricity on the WEM to cover Transmission Network losses and own needs;
2) Require the Parties to pay for the services provided;
3) Exercise other rights prescribed by the specified legal acts.

10. The Distributor, in accordance with the Law, the License, the Rules, and this Contract, undertakes to:
1) Provide distribution services to the WEM Trade Participants;
2) Register the data of the Metering Complexes of the WEM Participants connected to the Distribution Network, including readings of Commercial and Control Meters;
3) Ensure the completeness and availability of access to the registered data for the EMO through the real-time Automated Metering System, the MMS, or other available software;
4) Perform other functions arising from the provision of electricity distribution service.

11. The Distributor, in accordance with the Law, the License, the Rules, and this Contract, has a right to:
1) Procure electricity at the WEM to cover Distribution Network losses and own needs;
2) Require the Parties to pay for the services provided;
3) Exercise other rights prescribed by the specified legal acts.

12. The BSP plant, in accordance with the Law, the License, the Rules, and this Contract, shall be responsible for:
1) Providing balancing services by trading the electricity needed for balancing;
2) Selling electricity on the regulated component of the Bilateral Contracts Market at quantities defined and prices regulated by the Commission;
3) Publishing in the MMS the sale price of electricity for that TD for balancing purposes for all Trading Periods if it is lower than the maximum BSP price set by the Commission;
4) Complying with all Dispatch Instructions of the ESO on balancing the supply and demand for the TD;
5) Ensuring the implementation of technical power flows, including in Emergency Situations;
6) Ensuring the fulfillment of other obligations prescribed by the specified legal acts.

13. The BSP plant, in accordance with the Law, the License, the Rules, and this Contract, has a right to:
1) Purchase electricity on the WEM in case of failure to fulfill its contractual obligations using its own generation of electricity;
2) Purchase and sell electricity in cases defined by the Rules;
3) Export and import electricity;
4) Demand the WEM Trade Participants pay for the sold electricity;

5) Exercise other rights.

14. The rights defined as per sub-Provisions 1-3 of Provision 13 of this Contract may be exercised by the BSP on condition of priority fulfillment of obligations under sub-Provisions 1 and 2 of Provision 12 of this Contract.

CHAPTER 3. PAYMENTS GUARANTEES

15. The services being provided in the WEM as well as the electricity purchased in the WEM shall be paid for by the WEM Participants in procedures established by the Rules.
16. Within the context of this Contract, the amounts of payments for services provided in the WEM and for electricity purchased in the WEM shall be considered as:
    1) Equal to tariffs approved by the Commission, except for cases specified in sub-Provisions 2 and 3 of this Provision;
    2) Fixed, upon agreement of all the Parties, if
        a. No tariff has been defined by the Commission for the given service as well as for electricity provided by the given seller;
        b. The Parties have agreed upon a price less than the tariff (as long as such agreements are not discriminatory for other WEM Participants);
    3) Estimated by the EMO in the cases of electricity trade on the DAM or on the BALM pursuant to the Rules.
17. The Parties shall be obliged to make all payments due in full and on time as established by the Rules and prescribed by this contract, as well as by transactions executed and documents signed pursuant to the Rules, and only then to undertake actions for settlement of possible disputable issues.
18. In order to buy or import electricity and to receive services on the WEM, the WEM Trade Participants, excluding the Universal Supplier, Generator, Transmitter, and BSP, shall provide to the EMO a bank guarantee issued by any commercial bank operating in the Republic of Armenia (RoA) in procedures prescribed by the Rules and this Contract.
19. The Universal Supplier shall ensure that payments are made in accordance with regulations on Special Account (Accounts) of the Rules.

CHAPTER 4. INFORMATION ACCESSIBILITY AND CONFIDENTIALITY

20. For implementation of this Contract, any and all information subject to sharing between the Parties shall be shared and the documents shall be handed over in a manner prescribed in the Rules.
21. In cases of non-provision of information, delayed provision, or provision of false or incomplete information subject to sharing by all Parties for the implementation of this Contract, any Party shall bear liability for damages resulting from such non-provision.
22. All information disclosed by all Parties to each other for implementation of this Contract shall be used by them exclusively for the purposes of this Contract.

CHAPTER 5. EMERGENCY SITUATIONS

23. In cases defined by the ETN Code, when an Emergency Situation is declared, the WEM Participants shall operate exclusively based on the dispatch instructions of the ESO. The obligations assumed under the Transactions shall be suspended for the entire period of the Emergency Situation and measures defined by the Rules for violation thereof shall not be undertaken.
24. In Emergency Situations, electricity shall be sold at the maximum price defined by the Commission for the BSP, except for those plants for which the Commission has set a tariff. For these plants, the sale of electricity shall be performed at the tariff set by the Commission. At the same time, electricity shall be purchased at the actually formed average weighted price of electricity sale.

25. Within 10 business days from the ESO's declaration of the end of the Emergency Situation and the beginning of the trading restart period, the ESO, in cooperation with the EMO, shall submit to the WEM Participants and the Commission the calculations on services actually provided by WEM Participants and the price of electricity actually delivered (purchased) during the Emergency Situation, according to Provision 24 of this Contract (ES calculation).
26. Within 3 business days from the receipt of the ES calculation from the EMO as described in Provision 25 of this Contract, the Commission and the WEM Participants shall submit to the EMO their conclusions in writing. If the parties agree with the ES calculation result, the EMO shall download it to the MMS, while in case of disagreements and disputes regarding calculations, the WEM Participants shall be guided by this Contract and the Rules.

CHAPTER 6. RESPONSIBILITIES OF PARTIES

27. Where a Party failed to comply with or inadequately complied with responsibilities arising from this Contract and from the Transactions, it shall compensate the other Parties for damages suffered due to this failure in procedure defined by the Law.
28. In the event of a violation of the payment terms in accordance with this Contract, one party shall be entitled to inflict a penalty on the breaching party equal to 0.1 percent of the unpaid amount for each delayed day. If such a penalty is calculated, the cost of the delivered electricity shall be repaid first from the payments made according to the limitation period for its payment, and only after that shall the calculated penalty be paid.
29. The WEM Participants shall not be responsible for violations if they happen due to force majeure circumstances. Force majeure circumstances, as well as the procedure for their application, are defined by the Rules.
30. The EMO shall not be responsible for obligations arising from the Transactions concluded through the MMS software, except for violations of requirements for operation of the software specified in the Rules.

CHAPTER 7. CONTRACT VALIDITY PERIOD

31. This contract is deemed to be a contract of adhesion (offer) in terms of Article 444 of the RoA Civil Code, to which any person being entitled to electricity generation, supply, universal supply, wholesale electricity trade, as well as any qualified customer who has a right under the Law and the Rules to participate in WEM.
32. For each WEM Participant this contract shall enter into force immediately upon the registration of such participant in the MMS software and shall remain in force until the termination of the WEM participation in the manner prescribed by the Rules.
33. According to Annex 1 of this contract (Acceptance for adhering to the Wholesale Electricity Market Contract) all Acceptances signed by WEM Participants and registered by the EMO shall form an integral part of this contract.

CHAPTER 8. APPLICABLE LEGISLATION AND INTERPRETATION OF CONTRACT

34. The definitions of this Contract shall be interpreted in accordance with their meanings defined in the Law and the Rules, unless otherwise stipulated in this Contract.
35. If establishing a Wholesale Electricity Market New Model Contract (offer) or amending the present Contract, the terms of this Contract shall be deemed to be respectively amended, in compliance with the procedure and timeframe set by the corresponding decision of the Commission.

CHAPTER 9. DISPUTE RESOLUTION

36. Where a dispute or disagreement arises between the WEM Participants, the parties shall resolve them through negotiations.
37. If a dispute (disagreement) is not settled by the parties, any party to a dispute (disagreement) may apply to the Commission requesting that it resolve the dispute within its jurisdiction, or may file a suit at a competent court, unless the parties have agreed to submit their dispute to arbitration.

SIGNATURES
Market Operator
System Operator
Transmitter
Distributor
Balancing Services Providing Generator

ACCEPTANCE

of adherence to the Wholesale Electricity Market Contract

_____, represented by _____
Name

_____, acting based on _____

adheres in full to the Contract as _____.

For Generators

License № _____

Issued ___ _____ ___

Type of licensed activity _____

Location address_____

Metering Complex data by each Metering Point _____

Installed capacity stated in the License _____

Capacity at each Metering Point, in case of connecting to the electric network at more than one metering points _____

For Qualified Customers

Consumption system location address _____

Metering Complex data by each Metering Point_____

Consumption system network connection capacity _____

Capacity at each Metering Point in case of connecting to the electric network at more than one metering point _____

For Universal Supplier, Suppliers

Activity area

WEM Trade Participant's accessible market segments in the WEM:

1. Bilateral Contracts
   - a. Regulated component ☐
   - b. Non-regulated component ☐
   - c. Long-term contracts component ☐
2. Day-Ahead Market ☐
3. Balancing Market ☐

Authorized representative of the WEM Trade Participant

Position (status) _____

Signature _____

___ _____.

Below is information on points of boundary (delivery), acceptance, and metering of electricity:

1. Points of boundary (delivery) _____
2. Commercial (control) metering points_____
3. Commercial (control) meter, metering transformer data:

Location	Meter				Metering Transformer					Party responsible for the integrity of commercial meters, metering transformers in the territory being the property of or controlled by the WEM Trade Participant	
					Current			Potential			
	Type, nameplate, type and number of the seal	Permissible current (A)	Nominal voltage (V)	Month and year of the next meter calibration	Type, nameplate, type and number of the customer seal	Accuracy class	Transformation ratio	Type, nameplate, type and number of the customer seal	Accuracy class	Transformation ratio	
1	2	3	4	5	6	7	8	9	10	11	12

For Qualified Customers:

Below is information on technological and/or emergency capacities:

Maximum permissible capacity	Technological capacity	Emergency capacity	Duration of technological process (cycle)	Period required for emergency capacity
kW	kW	kW	hour	hour

1. Emergency and/or technological capacities

No	Feeding center	Feeding line	Feeding line load, kW	Emergency backup			Technological backup			Other capacities		Sub-customer	
				Power receivers, power supply restriction of which can result in real and inevitable danger to human life and the environment	Feeding line emergency capacity, kW	Feeding line on which emergency capacity is transferred	Power receivers, power supply restriction of which can result in real and inevitable danger to human life and the environment	Feeding line technological capacity, kW	Feeding line on which emergency capacity is transferred	Capacity, kW	Daily electricity consumption, kWh	Total load, kW	Technological and emergency backup capacity, kW
1	2	3	4	5	6	7	8	9	10	11	12	13	14
Total													

2. Capacity to be cut off

No	Feeding center	Feeding line	Feeding line load, kW	Amount of technological and emergency reserved capacity on the feeding line, kW	Feeding line on which reserved capacity is transferred	Capacity to be cut off kW	Notes
1	2	3	4	5	6	7	8
Total							

3. Capacity that is not subject to being cut off until the end of the period required to ensure the duration of the technological process and emergency capacity

No	Feeding center	Feeding line	Feeding line maximum capacity kW	Emergency reserved capacity kW	Technological reserved capacity kW	Notes
1	2	3	4	5	6	7
Total						

OTHER TECHNICAL DATA

_____

WEM TRADE PARTICIPANT

LOCATION _____

BANK ACCOUNT NUMBER _____

PHONE _____

OPERATION LICENSE No_____

DIRECTOR _____

_____

(Signature, name, surname)

ARMENIA RETAIL ELECTRICITY MARKET TRADING RULES

SECTION 1. DEFINITIONS AND GENERAL PROVISIONS

CHAPTER 1. SUBJECT AND DEFINITIONS

1. The Retail Electricity Market Trading Rules (hereinafter, the REM Rules) shall define the principles of the Retail Electricity Market (hereinafter, the REM) operation, the rules of trading on the REM, the requirements of electricity supply and universal supply, the requirements for the Distribution Licensees, the Customer Supplier switching procedure, the consumed electricity metering and payment procedure, the Supplier-Customer relationship during commercial meter accuracy testing and disclosure of inaccuracies, the requirements for storage and transparency of REM data, as well as other necessary regulations and procedures to increase the efficiency of REM operation.
2. The main definitions used in these Rules are as follows:

1) Commercial Metering device	A metering device for commercial measurement of electricity specified in the Contract or in the Registration Card.
2) Failure of a Commercial Metering device	Failures of or damages to components of Commercial Meters verified by the metrological experts of the Metrology and Calibration body; or the absence of, tampering with, or damage to the seals of Commercial Meters (including modification of parameters or connection schemes of current and voltage metering transformers) or other interference with commercial meter operation.
3) Distributor	An entity holding an electricity (capacity) distribution license.
4) Confidential Information	Information or data on the financial status and commercial secrets of the Distributor, Universal Supplier, or Supplier, the publication of which may harm any of these, as well as Customer-related information available to the Distributor, Universal Supplier, Supplier.
5) Sub-Customer	A Customer who receives electricity supply through the consumption system of other Customers and has an Electricity Supply Contract with the Universal Supplier (the Supplier) signed under the defined procedures.
6) Universal Supplier	An entity holding a license for the universal supply of electricity.
7) Distribution Network Code	"Distribution Network Code of the Republic of Armenia Electricity Market," approved by the Commission.
8) Wholesale Electricity Market Rules	Wholesale electricity market trading rules approved by the Commission.
9) Autonomous Power Producer	A legal or physical entity producing electricity for own needs, with installed capacity not exceeding the aggregate capacity of all its electric loads and not higher than the capacity stated by the Law.
10) Vulnerable Customer	A residential Customer who has been given vulnerable Customer status in procedures defined by the Government of the Republic of Armenia (RoA) based on the fact of being socially marginalized or being awarded special status.
11) System Operator	An entity holding an Electricity System Operator service license.
12) Commission	The Public Services Regulatory Commission of the Republic of Armenia.

13) Settlement period	A period that comes into effect at 00:00 of the first day of a calendar month and ends at 23:59 of the last day of the same month.
14) Metering Device	An electricity meter or a Metering Complex with all connections to/from a meter as well as current and voltage transformers that has passed a meter calibration by the Metrology and Calibration Body.
15) REM Participants	The Supplier, Universal Supplier, Customers (except for Qualified Customers), and Autonomous Power Producers.
16) Supplier	An entity holding a license for electricity supply.
17) Supply Contract	A contract signed (to be signed) between the Supplier and the Customer that establishes the terms and conditions of electricity supply.
18) Market Operator	An entity holding an Electricity Market Operator service license.
19) Metrology and Calibration Body	An organization implementing state metrological supervision defined by the RoA Law on Uniformity of Measurements.
20) Contract	A contract on the provision of electricity distribution services and universal supply of electricity and/or on connection of the Consumption System to the electric network, distribution, and universal supply of electricity, according to the model form approved by the Commission.
21) Tariff	The maximum price or charge set by the Commission according to the Law for the sale of one unit of electricity and for the provision of services by Energy Sector Licensees.
22) Boundary Point	The border of balance ownership of electric facilities of REM Participants and the Distributor.
23) Customer	An entity in demand of electricity that has signed or is in the process of signing an electricity supply contract with an Electricity Supply Licensee (including a Universal Supply Licensee).
24) Consumption system of the Customer	The Customer's complex of electric installations.
25) Control metering device	A metering device for control measurement of electricity as stated in the Contract or in the Registration Card.

CHAPTER 2. PRINCIPLES AND OBJECTIVES OF REM OPERATION

3. The objectives of the REM Rules shall be targeted to ensure transparent and competitive conditions of REM operation, promote access for new Suppliers to the network, and guarantee protection of Customer rights.
4. REM operation is based on the following principles:
   1) Supply of electricity to Customers, including Vulnerable Customers by the Universal Supplier at regulated prices;
   2) Supply of electricity to Customers by Suppliers at non-regulated prices;
   3) Supplier selection and supplier switching opportunities for Customers (including Vulnerable Customers);
   4) Protection of rights of Vulnerable Customers by applying differentiated rates;
   5) Determination of Distributor's responsibility for violation of electricity service quality indicators;

6) Obligation of the Universal Supplier, Suppliers, and Distributor to ensure Customer access to the information defined by the REM Rules.

CHAPTER 3. REPORTING AND DOCUMENTATION

5. Sharing of information between the REM participants, the REM Participants, and the Distributor, as well as submission of documents shall be performed in an appropriate manner.
6. Sharing of information between the REM participants and the Distributor, as well as submission of documents within the framework of these Rules, shall be deemed appropriately performed if the information has been delivered with a signed receipt or sent through an electronic data sharing platform (if such is available to the recipient of information), or by a registered letter (including with a notice of delivery), or by electronic communication systems (including to the email address specified by the Customer), or by other means of communication securing the integrity of the message (including sending a message to a phone number specified by the Customer), which allow confirmation of the fact of receipt or, in cases defined by legislation, of appropriate notification of the receipt of the correspondence by the recipient, unless otherwise specified in these Rules.
7. The Customer shall be required to immediately inform the Distributor about any change of data regarding its address, email, or other means of communication. If such a notice is not sent, the information and the documents shall be provided to the recipient's last known address and the recipient shall bear all the risks associated with the adverse consequences of not providing the information.
8. If the recipient refuses to receive the correspondence or to sign the mail delivery confirmation (if it was sent via postal delivery), or if documentation sent by a registered letter is returned, the documentation shall be deemed appropriately delivered to the recipient by the sender on the 3rd day from the next day the documentation is available on its official website and on http://www.azdarar.am and the latest announcement on the opportunity for the recipient to become aware of the content thereof is published.
9. The Distributor (Universal Supplier) and the Supplier shall provide a written answer to a written inquiry and a verbal answer to a verbal inquiry of a Customer or an applicant, and in case of an electronic mail, the answer shall be provided by email within 10 business days after the receipt of the inquiry (except for a verbal inquiry) unless otherwise provided by REM rules. The answer to a verbal inquiry shall be provided verbally immediately after the inquiry is received or in the shortest possible time.
10. The REM Participants and the Distributor shall be responsible for the reliability of information (documents) provided.
11. Where errors have been revealed in the data and documents shared among the REM Participants or between the REM Participants and the Distributor, the data shall be corrected within 3 business days after the error is revealed and a corresponding notification is sent, unless otherwise defined in the REM Rules.
12. Information (documents) shared among the REM Participants, shared between the REM Participants and the Distributor, as well as submitted by the REM Participants and the Distributor to the Commission shall be open to the public if not deemed confidential according to the Law.
13. Information (documents) specified in Provision 12 of the REM Rules may be published in legally defined procedures. The entity that published the information shall bear responsibility for violations of legally defined requirements on publication of such information (documents).
14. Any document or information provided in these Rules shall be preserved for at least a 5-year period, unless a longer period is defined by the REM Rules or the RoA legislation for storage of that type of documentation.

CHAPTER 4. RESPONSIBILITIES OF REM PARTICIPANTS, DISPUTE (DISAGREEMENT) RESOLUTION

15. For non-compliance or inadequate compliance with the provisions of the Rules, the REM Participant and the Distributor shall bear responsibility under procedures defined by RoA Legislation, the REM Rules, and the Contract.

16. The REM Participant and the Distributor shall not be responsible for violations defined in these Rules if they happened due to force majeure circumstances.
17. Under the REM Rules, any circumstance or event (or after-effect of that event) that led (or leads) to non-fulfillment or inadequate fulfillment of obligations defined by REM Rules and at the same time is characterized by the features stated below is considered a force majeure situation:
    1) The circumstance or event is out of the control of the party affected by a force majeure situation;
    2) The party affected by force majeure situation undertook all possible actions and efforts (including precautional, alternative, legally defined) to prevent, weaken, eliminate, or avoid the influence of those circumstances (after-effects).
18. Under the REM Rules, the following situations in particular are considered force majeure:
    1) Natural and man-made calamities; epidemies; acts of God (including floods, earthquakes, hurricanes, tornados, thunderstorms, heavy rains with lightning, snowstorms, and landslides); nuclear, chemical or biological contamination; strikes; and public disorders;
    2) Rebellions, terroristic acts, wars, invasions, armed conflict, actions of foreign enemies, and blockades that take place on or involve the territory of the RoA and could not be reasonably predicted;
    3) An act, activity, or inactivity of a state or municipal agency or other authorized body, due to which no permission or right was issued or extended to facilitate the fulfillment of obligations stated in this License, or due to which fulfillment of obligations was hindered, on condition that the REM Participant and Distributor acted in compliance with RoA legislation.
19. If a force majeure situation occurs, the affected party shall notify the other party about such circumstances within 10 days after hearing of or being impacted by those circumstances. The party that failed to notify the other party shall bear the risks associated with negative impacts of non-notification.
20. Provision 16 of the REM Rules shall not restrict the right of the REM Participant and the Distributor to apply to the Commission in extraordinary and unavoidable situations other than those described above to acknowledge those as force majeure, if requirements of this Chapter are satisfied.
21. Disputable issues arising between the REM Participants and the Distributor shall be solved through negotiations.
22. If a dispute (disagreement) is not settled by the parties, any party to a dispute (disagreement) may apply to the Commission requesting that it resolve the dispute within its jurisdiction, or may file a suit at a competent court, if the parties fail to agree on solving the issue by arbitration.

SECTION 2. RULES FOR ORGANIZING TRADE IN THE REM

CHAPTER 5. GENERAL PROVISIONS

23. The Customers may purchase electricity in the REM from the Universal Supplier or the Suppliers at their discretion, except for vulnerable consumers, which may purchase electricity from the Universal Supplier only.
24. Distribution and universal supply of electricity on the REM by the Universal Supplier (Distributor) shall be implemented based on the Contract, whereas the supply of electricity by the Supplier shall be based on the Electricity Supply Contract.
25. Switching from the Universal Supplier to another Supplier or switching between Suppliers upon the initiative of a Customer shall be carried out based on the REM Rules, not exceeding 4 times per calendar year. Supplier of Universal Supplier switching shall be registered by the Distributor by making a corresponding record in the individual registration card activated for the given Customer (hereinafter, the Registration Card).
26. In cases when more than one consumption system belongs to the given Customer (regardless of their location and the number of connection points), the latter shall have the right to conclude one unified Contract for all of them or separate Contracts for each of them.
27. The Distributor (Universal Supplier) shall not be allowed to request that the Customers make payments or compensations, provide information or documents, or to burden them with obligations if this is not required by the REM Rules, the Contract, or other standard legal acts.
28. Transmission of electricity by the Customer through its electric facilities to feed the Sub-Customer's networks or other networks of the Distributor as required by the Law shall be implemented in compliance with Annex 1 of the REM Rules.
29. Regulation of relationships within the context of providing compensation for electricity supplied by the Autonomous Power Producer and the Distributor shall comply with procedures defined in Annex 2 of the REM Rules.

CHAPTER 6. UNIVERSAL SUPPLIER REQUIREMENTS

30. In compliance with the Law, the License, the REM Rules, and the Contract, the Universal Supplier shall:
    1) Supply electricity to each Customer who does not have a Supply Contract signed with another Supplier for the given period;
    2) Supply electricity to Vulnerable Customers;
    3) Fulfill other functions associated with the universal supply of electricity.

CHAPTER 7. ELECTRICITY DISTRIBUTOR REQUIREMENTS

31. In compliance with the Law, the License, the REM Rules, and the Contract, the Distributor shall:
    1) Provide electricity distribution services on a non-discriminatory basis;
    2) Register the Customer's Commercial metering data and, in case of violation, perform recalculation;
    3) Pay a penalty to the Customer in case of violation of service quality indicators;
    4) Provide information free of charge to the Supplier on the quantity of electricity supplied to the Customer who has signed a contract with the latter;
    5) Provide an invoice to the Customer on the quantity and cost of electricity supplied and, in case of the Supplier's Customer, on the quantity and cost of the distribution service rendered;
    6) Ensure the availability of a 24-hour telephone line through which, by informing the Customer in advance about recording the phone call, the Distributor shall provide information or clarification to the Customer regarding the following:

a) Procedures for the conclusion of the Contract and relevant documentation;
b) Reasons for the interruption, suspension of, and deadlines for restoration of electricity supply;
c) The quantity, tariff, and cost of electricity supplied, and in case of the Supplier's Customer, the quantity, tariff, and cost of the distribution service rendered, as well as payment deadlines and penalties for violation of payment deadlines;
d) Cases of payment of penalties by the Distributor;
e) Procedures on submission of claims and applications by Customers and responses by the Distributor;
f) Other issues associated with the provision of services by the Distributor.

7) At service centers and on its official website, provide the model forms of the Contact and make available the information specified in sub-Provision 6 of this Provision;
8) Maintain the Electronic Registry that includes all Customer Registration Cards and protect it from unauthorized access in accordance with the requirements of ISO/IEC 27001 and ISO/IEC 27002;
9) Implement other functions resulting from the provision of distribution services.

32. The Customer's Registration Card shall include the following information:
1) The Contract concluded with the Customer and bases for the conclusion thereof;
2) Data on Commercial meters and acts (protocols, conclusions) on their dismantling, testing, replacement, or installation;
3) Information on Points of Connection to the Customer's consumption system and Boundary points;
4) In cases defined in the EDN Code, the description, capacity, and operation hours of the Customer's consumption system;
5) Monthly values of technological losses of electricity that occur between the point of installation of the Commercial Meter and the Boundary Point;
6) Duration of the minimum load period, values of aggregate loads connected during that period, and the procedure on calculation of that loads;
7) Data specified in Provision 84 of the REM Rules;
8) Documents and data on recalculations performed;
9) Information on monthly consumption of electricity, payments of the Customers, and penalties paid by the Distributor;
10) Annual electricity demand applications of the Customer (if available);
11) In case of the conclusion of a Supply Contract with another Supplier, the name of the Supplier and the supplier switching date;
12) In case of fixed technological or emergency capacities reserved by the Customer, also: emergency and technological capacities, duration of the technological process (cycle) required to provide emergency capacity, capacity not subject to disconnection until the end of the period needed to ensure technological process and provide emergency capacity, feeding center, feeding line, and the maximum capability of the feeding line;
13) Information on changes in the Registration Card records and on the person who made the changes.

33. The Distributor shall ensure access to the data recorded in the Customer's Registration Card during the entire period of validity of the Contract, then archive and store the data for at least 10 years after termination of the Contract.
34. If requested by the Customer, the Distributor shall provide to the latter the printed version of the data specified in the Registration Card.
35. If an error is revealed in the Registration Card, the Customer and the Distributor shall be guided by procedures described in the REM Rules on making corrections in invoices.
36. The Customer shall be given the right of access to the electronic registry to obtain information about itself from the electronic register.

CHAPTER 8. SUPPLIER REQUIREMENTS

37. In compliance with the Law, the License, the REM Rules, and the Contract, the Supplier shall:
    1) Supply electricity at non-regulated prices pursuant to the requirements of the Supply Contract;
    2) Provide an invoice to the Customer on the quantity and cost of electricity supplied;
    3) Have a service center and a website where the Customer may get information and clarifications on the following:
        a) Procedures and relevant documentation for the conclusion of the Supply Contract;
        b) The quantity and cost of electricity supplied, deadlines for payments, and consequences of violations thereof;
        c) Procedures on submission of claims and inquiries by Customers and provision of responses by the Supplier,
        d) Other issues related to the provision of services by the Supplier;
    4) Ensure availability of the model form of the Contact at the service center and on its official website.

CHAPTER 9. CONCLUSION OF CONTRACT

38. The Contract shall be open to the public and concluded by the Customer based on the Acceptance submitted pursuant to the model form defined by the Commission and shall become effective from the moment of approval of the Acceptance by the Distributor, except for the contract on connection of the consumption system to the electric network, distribution, and universal supply of electricity, which shall be concluded in procedures defined by the EDN Code.
39. The Customer shall submit the Acceptance to the Distributor in writing or in the form of a printed document (with a handwritten signature of the Customer), or by electronic means allowing the Distributor to confirm its authenticity and to decide that the Acceptance is sent by the Customer, including sending the Acceptance with an electronic digital signature of the Customer or sending it from the preliminary provided email address to the Distributor's official email address, whether or not there is an electronic digital signature.
40. In addition to the Acceptance, the Customer, if it is a Residential Customer, shall also submit the copy of a document confirming its identity, the copy of a document certifying (confirming) the rights or acquisition of the rights of the Customer to the premises receiving electricity supply (building, construction), and, in the case of a legal entity, the document certifying the rights of the latter to the premises receiving electricity supply (building, construction). In case of connection to a 6(10) kV network, the Customer shall present the copy of the decision (permit) for commissioning of the electric installations issued by the State Technical Supervisory Authority and information on the operative personnel (persons in charge of the electric facility) defined pursuant to the technical regulation approved by the RoA Government.
41. Where the rights of Residential Customers (including ownership or use) to the premises receiving electricity supply (building, construction site) are not registered in procedures defined by the RoA legislation, whereas a reference is available provided by a competent authority verifying the fact of inhabitancy (and if it is a garage, the fact of occupancy of the premises receiving electricity supply), the Distributor shall assess the feasibility of electricity supply to the Customer and associated risks and only then be eligible to sign a contract.
42. Where the Acceptance does not comply with the model form or the electricity supply to the Customer does not comply with the requirements of legal normative acts, the Distributor, within 1 business day after receipt of the Acceptance, except for the case specified in Provision 44 of the REM Rules, shall return it to the Customer supported by the corresponding justification. In case of absence of justification for returning the Acceptance as defined in this Provision, the Distributor shall, within the same period, approve the Acceptance and notify the Customer of the conclusion of the Contract.
43. Immediately after the conclusion of the Contract, the Distributor shall open and maintain a Registration

Card for the given Customer with its registration number and share that number with the Customer along with the login and password to its personal page, thus giving the Customer access to the relevant information.

44. In cases when the Customer does not have rights or documents certifying the acquisition of rights to the premises receiving electricity supply (building, construction site) as prescribed by the REM Rules, and when the Acceptance is submitted in compliance with the REM Rules by a person who has such rights to the premises receiving electricity supply (building, construction site), the Distributor shall approve the Acceptance pursuant to the REM Rules within 1 business day after termination of the Contract.
45. The Contract shall be signed for an uncertain period, the following cases excluded:
    1) Temporary connection in procedures defined by the Distribution Network Code, when the Contract is signed for the period of effectiveness of that connection;
    2) The case specified in Provision 41 of the REM Rules, when the Contract is concluded for 1 year maximum;
    3) The case specified in Provision 54 of the REM Rules, when the Contract is concluded until the dispute is ultimately solved in legally defined procedures.
46. If a specific case provided for in the REM Rules requires the conclusion of a temporary Contract, then 1 month before the completion of the effectiveness of that Contract, each party to the Contract may notify the other party of the termination of the Contract. If, upon completion of the effectiveness of the Contract, the Customer keeps consuming electricity in the absence of a notification by the Distributor, the Contract shall be deemed extended on the same conditions and for the same period, except for the case defined in sub-Provision 1 of Provision 45 of these Rules, when the Contract could not be extended.
47. Within a maximum of 3 business days after the conclusion of the Electricity Distribution and Universal Supply Contract, and in case of connection of the consumption system to the electric network and signing of the Electricity Distribution and Universal Supply Contract, after the completion of connection works, the Distributor shall be obliged to ensure provision (possibility) of electricity supply to the Customer.

CHAPTER 10. MODIFICATION, SUSPENSION, AND TERMINATION OF CONTRACT

48. The Contracts concluded as a result of the approval of the new model form or modification of the Contract by the Commission shall be deemed concluded or modified according to the Contract in compliance with the new or modified form, starting the date that the corresponding legal act of the Commission enters into force.
49. The Distributor shall notify the Customers of the approval of the new form of the Contract or modification therein as prescribed in Provision 48 of the REM Rules in terms and procedures defined by the Commission.
50. Upon agreement between the parties, modifications to the Contract and the Acceptance may be done in writing on the condition that they do not contradict the acting model form approved by the Commission and other acts of the Commission.
51. In case of switching from the Universal Supplier to another Supplier, provision of electricity universal supply service under the Contract shall be terminated, not relieving the Customer from fulfillment of its contractual obligations, and in case of a violation thereof, from the defined responsibilities.
52. The Contract may be terminated in the following cases:
    1) Upon mutual agreement of the parties;
    2) Unilaterally, by the Customer on condition that the latter duly informed the Distributor and completely paid for electricity supplied and, in the case of the Supplier's Customer, for distribution services rendered.
    3) Unilaterally, by the Distributor:
        a) In case the Contract signed for a certain period in accordance with Provision 45 of the REM

Rules is expired, on the condition the Customer was duly notified of that fact 1 month prior to the expiration date,

b) In the case that the entity having the rights to the premises receiving electricity supply (building, construction site) has submitted a written request, if the Customer does not have a document verifying his eligibility or acquisition of rights to the premises (building, construction site) as prescribed by the REM Rules, on condition that the Customer has been informed in advance, except for the case specified in Provision 53 of the REM Rules;

c) Upon the death of a residential Customer or liquidation of a legal entity;

d) In the event that the justification for returning the Acceptance specified in the REM Rules, or rejecting the Application for the Contract specified in the EDN Code, are revealed, on condition that the Customer has been notified in advance;

e) In case of obtaining Qualified Customer status in compliance with the WEM Rules;

f) In other cases prescribed by the Law, REM Rules, Contract, and other legal acts of the Commission, on condition that the Customer has been notified in advance.

53. Where the rights to the premises (building, construction site) receiving electricity supply are disputable, then according to sub-Provision 3 of Provision 52 of the REM Rules, the issue of termination of the Contract shall be resolved after the settlement of the dispute in procedures defined by RoA Legislation.

54. Where the dispute regarding the rights to the premises (building, construction site) receiving electricity supply occurred or the Distributor has been informed about the dispute after the termination of the Contract as specified in point (b) of Provision 52 (3) of the REM Rules and the conclusion of the Contract with the new rights holder, within 1 business day from the day the Distributor was notified about the dispute, the effectiveness of the newly signed Contract shall be deemed suspended and a temporary Contract with the previous Customer under the previous conditions shall be deemed effective until the dispute is ultimately resolved in legally defined procedures, of which the Distributor shall, within the same period, inform the parties.

55. Modification to or termination of the Contract shall not relieve the parties from the fulfillment of accepted and outstanding obligations under the Contract.

CHAPTER 11. SUPPLIER (UNIVERSAL SUPPLIER) SWITCHING AND CONCLUSION OF ELECTRICITY SUPPLY CONTRACT

56. The Customer shall be eligible to switch to another Supplier instead of the Universal Supplier or to replace the selected Supplier with another Supplier by initiating a procedure for conclusion of a Supply Contract, on condition that:

1) The Customer has a contract with the Distributor;

2) The metering device of the Customer meets the requirements of the Distribution Network Code and is included in the automated system of electricity metering and control (ASEMC);

3) The Customer does not appear to be a Vulnerable Customer;

4) The Customer did not exceed the number of Supplier switches stated in Provision 25 of the REM Rules.

57. The Supply Contract shall contain at least the following information:

1) Cost or charge for electricity to be supplied;

2) Payment procedures and consequences of violation;

3) The effective period of the Contract;

4) The Contract termination procedure.

58. No service fee shall be charged to the Customer for the conclusion of a Supply Contract.

59. The unsatisfied liabilities toward the Current Supplier or Distributor (Universal Supplier) shall not deprive the Customer of its right to sign a Contract with another Supplier.

60. At least 10 business days prior to the date requested by the Customer for the conclusion of the Contract,

the latter shall submit an application to the new Supplier enclosing thereto the copy of the document verifying its identity (copy of the state registration certificate).

61. Within 1 business day after receiving the Customer's application, if it has no intention to sign the Contract with the Customer, the Supplier shall inform the latter of that fact; if it does intend to sign, it shall:
    1) Inform the Customer of the duration and conditions of the Supplier Switching Procedure;
    2) Provide a sample of the Supply Contract;
    3) Notify the Customer about the termination of the universal supply according to Provision 51 of the REM Rules.
62. In case of disagreement with the Contract conditions proposed by the Supplier, the Customer may cancel its application before signing the Contract.
63. If it intends to sign a Supply Contract with the Customer, the Supplier, within 1 business day after receiving the application referred to in Provision 60 of the REM Rules, shall send the application to the Distributor.
64. Once the application is received as prescribed in Provision 63 of the REM Rules, the Distributor shall, within 1 business day, check its compliance with the requirements defined in Provision 56 of the REM Rules:
    1) If compliance is confirmed, the Distributor informs the Supplier;
    2) If incompliance is revealed, the Distributor sends to the Supplier a notification on rejection, specifying grounds for the rejection.
65. Where the Customer is in more than one Supplier Switching process, the Distributor shall take as a basis the Customer's latest request for Supplier Switching.
66. If the Customer complies with Provision 64 of the REM Rules, the Supplier shall sign a Contract with or notify the latter about the rejection.
67. Within 1 business day after the signing of the Contract, the Supplier shall inform the Distributor, which in turn shall register the Supplier Switching by making a corresponding record in the Customer's Registration Card and providing access for the Supplier and EMO to the information regarding the connection facilities, Commercial meter identification, and previous consumption volumes of the Customer in the ASEMC.

CHAPTER 12. TERMINATION OF SUPPLY CONTRACT

68. The Supply Contract shall be terminated:
    1) Upon mutual agreement of the parties;
    2) Upon the initiative of the Consumer, notifying the Supplier at least 10 business days before the termination date;
    3) Upon the initiative of the Supplier, in procedures defined by the Supply Contract or the Law by notifying the Customer and the Distributor at least 10 business days before the termination date;
    4) In case of terminating the Contract with the Distributor.
69. Within 1 business day from the receipt of the notification referred to in sub-Provision 2 of Provision 68 of the Rules, the Supplier shall notify the Distributor and the EMO. Once the notification by the Supplier is received, the parties shall be guided by the REM Rules.
70. Termination of the Supply Contract shall not relieve the parties from the fulfillment of liabilities under that Contract.

SECTION 3. METERING AND BILLING PROCEDURES FOR ELECTRICITY SUPPLIED AND DISTRIBUTION SERVICES RENDERED

CHAPTER 13. GENERAL PROVISIONS

71. Electricity metering requirements shall aim to ensure the integrity, uninterruptedness, transparency, and unity of the Commercial metering.
72. The data on the Commercial Metering device and Control Metering device shall be stated in the Registration Card.

CHAPTER 14. PROCEDURE FOR MEASURING THE QUANTITY OF SUPPLIED (DISTRIBUTED) ELECTRICITY

73. The quantity of electricity supplied shall be computed by the difference of the Customer's Commercial Meter readings taken in the Settlement month or by multiplying that difference by the transformation ratio (current and voltage transformer ratios). If the Commercial Meter immediately registers the quantity of electricity as supplied during the settlement month, then this quantity shall be accepted. If the Commercial Meter is located beyond the boundary point, then the amount of technological losses that occurred at electric installations between the point of location of the meter and the boundary point shall be subtracted from or added to the quantity of electricity registered by the Commercial Meter, and this calculation approach shall be stated in the Registration Card. Where sub-Customers or other networks of the Distributor have been connected to the Customer's electric installations, only technical losses corresponding to the load of that Customer shall be calculated. In case of violations of the integrity of the Commercial meter, the quantity of electricity consumed shall be determined according to the requirements of Chapter 17 of the REM Rules.
74. For Customers of 0.4 kV voltage and above (except for residential Customers), where the normal operation of Commercial Meters in minimum load regimes is technically unfeasible, the quantity of electricity supplied shall be calculated based on the capacity of actually connected electricity-consuming devices throughout the entire period of minimum load and added to the quantity of electricity calculated based on the readings of the Commercial (Control) meter. The duration of minimum load periods and the aggregate load connected during those periods and data on the procedure for their calculation shall be stated in the Registration Card and may be revised upon the written request of one of the parties in case the minimum load is changed.
75. The readings of the Commercial (Control) Meter shall be recorded by the Distributor within the first 3 days of the month following the given Settlement month. If electricity supplied is being metered by a multi-tariff electronic meter (hereinafter, the e-meter), the Distributor shall register the consumption of the Customer during the previous Settlement month (by time frames), which is automatically displayed on the Commercial Meter data panel, instead of recording the Commercial (Control) Meter reading.
76. The Distributor shall be required to record readings of the Customer's Commercial Metering device (except for residential Customers) in the presence of its representative if the latter applied with such a request in writing. In such a case, the Distributor shall record the Commercial Meter data jointly with the Customer within the period defined in Provision 75 of the REM Rules and agreed upon with the Customer. The Distributor shall have the right to take the meter reading unilaterally if the Customer's representative fails to show up at the mutually agreed time.
77. If the Commercial (Control) Meter is included in the ASEMC, the Distributor shall be obliged to record the Commercial Meter readings by means of ASEMC by collecting all the recorded data of the Commercial Meter as well.
78. If electricity delivered to the Customers is metered by a meter included in the ASEMC, then in case of a written request of the latter, not later than 5 business days from receipt of the request, the

Distributor shall be obliged to provide access to the ASEMC for the given Customer, and if necessary, for its Supplier as well for the entire data related to that Customer for the monitoring purposes.

79. For a Supplier's Customer, the Distributor shall provide to the Supplier all readings of Commercial Meters related to the Supplier's Customers not later than the 5th day of the month following the Settlement month.

CHAPTER 15. PROCEDURE ON CALCULATION AND PAYMENT OF THE COST OF ELECTRICITY SUPPLIED AND DISTRIBUTION SERVICES PROVIDED

80. The cost of electricity supplied to the Customer during the settlement month shall be computed as a product of the Tariffs set forth by the Commission for the given voltage level and the given timeframe (if the Commercial Meter is capable of differentiated calculation) and the energy quantities supplied, except for cases defined in Provision 82 of the REM Rules.

81. In case of a Supplier's Customer, the cost of electricity supplied to the Customer within the Settlement month shall be determined according to the Supply Contract between them, and the cost of distribution services rendered shall be determined as a product of the distribution service tariff set forth by the Commission for the given voltage level and the quantity of distributed electricity.

82. To restore the Customer's electricity supply from the Universal Supplier in cases prescribed by the REM Rules, as well as in cases when no status of Qualified Customer is obtained or no Supplier is selected in terms and procedures defined by the REM Rules and WEM Rules approved by the Commission, the cost of electricity supplied to the Customer by the Universal Supplier within the Settlement month shall be calculated as a product of the tariff set forth by the Commission for the given Customer group and the quantity of electricity supplied.

83. The Distributor (Universal Supplier) shall be required to do the following before the 10th day of each month:
    1) Twice a day from 18:00 to 20:00 and from 20:00 to 23:00 through at least 1 public television channel, inform the Customers about the day of placing the information specified in sub-Provision 2 of this Provision;
    2) Make available at the corresponding service outlets of the RoA operating banks, payment terminal networks, and postal departments that have signed a contract with the Distributor (Universal Supplier) the information on the quantities and cost of electricity supplied by the Distributor (Universal Supplier) to the Customers during the previous month, and in case of Supplier's Customers, on the quantity and cost of distribution services rendered.

84. In the bill provided by the Distributor (Universal Supplier) to the Customer for the quantity and cost of electricity supplied and in the case of Supplier's Customer, for the quantity and cost of distribution services rendered in the Settlement month, the following information shall be reflected:
    1) First name, last name, title of the Customer, location (residence address), Registration card number, Settlement month, the previous and latest readings of the Commercial Meter (in case of e-meters, the quantity of electricity supplied by timeframes), the day of registration of the previous and latest readings of the Commercial Meter, the quantity of electricity supplied during the Settlement month (in kWh, and if e-meters are available, the quantity of electricity supplied by timeframes), the cost of electricity (in AMD, including VAT), the quantity of electricity supplied during the same month of the previous year (in kWh, and if e-meters are available, the quantity of electricity supplied by timeframes), remaining debt at the beginning and the end of the Settlement month (in AMD, including VAT), and the payment date;
    2) In case of the Supplier's Customer, first name, last name, title of the Customer, location (residence address), Registration card number, Settlement month, the previous and latest readings of the Commercial Meter, the day of registration of the previous and latest readings of the Commercial

Meter, quantity and cost of distribution services rendered, remaining debt at the beginning and the end of the Settlement month (in AMD, including VAT), and the payment date.

85. In case of a written request by the Customer, each month starting the month following the receipt of the request, within the period specified in Provision 83 of the REM Rules, the Distributor shall notify the Customer in a way chosen by the latter (by post or email) about all indicators that were used to calculate the quantity and cost of electricity supplied and, in the case of the Supplier's Customer, quantity and cost of distribution services rendered during the previous Settlement month. If the notification is delivered via the post office, then the associated charges should be covered by the Customer; if it is sent via email, the service should be free of charge. The charges for postal delivery shall be included in the bill as a separate line.
86. The Customer shall be obliged to pay the cost of electricity supplied and, in the case of the Supplier's Customer, the cost of distribution services rendered in terms and procedures defined in Provision 83 of the REM Rules within 7 days of receipt of the bill from the Distributor (Universal Supplier) or after being notified.
87. In case of violation by the Customer (Residential Customer excepted) of the period of payment for electricity supplied and by the Supplier's Customer, for the cost of distribution services rendered, as defined in Provision 86 of the Rules, the Distributor (Universal Supplier) shall be eligible:
    1) To calculate a penalty for each day of delinquency for the amount stated in the Contract. The penalty shall be calculated not earlier than 7 days after being duly notified in procedures defined in Provision 83 of the Rules;
    2) In cases of recurrent violations during the 12 months following the first violation, within the 3 successive months of the last violation, to claim an advance payment from the Customer or any other acceptable payment guarantee, the size of which cannot exceed 50 percent of the average monthly cost of electricity consumed by the Customer during the previous year. If the Customer refuses to provide an advance payment or any other payment guarantees acceptable for the Universal Supplier (Distributor), then the Universal Supplier (Distributor) shall have the right to suspend the Customer's supply after duly notifying the Customer 3 business days in advance. If the Customer has a contractually specified emergency or technological capacity, then the Supplier shall have the right to suspend the service only after completing all the procedures described in EDN Code.
88. In case of violation of the period defined by Provision 86 of the REM Rules for payment of the charge for electricity supplied and, in case of the Supplier's Customer, for distribution services rendered, except for cases specified in the EDN Code, the Distributor shall be eligible to terminate the Customer's electricity supply under the EDN code.

CHAPTER 16. PROCEDURE FOR SETTLEMENT OF ERRORS IN PAYMENT DOCUMENTS

89. Where errors are revealed in the payment documents or bills for electricity supplied and, in case of the Supplier's Customer, for distribution services rendered, the Customer shall apply to the Distributor in writing to request elimination of errors. Within 5 business days from the receipt of the Customer's application, and in 10 service days if an additional inspection is needed, the Distributor shall discuss the Customer's application and inform the Customer about the results.
90. If the Distributor reveals errors in the payment document or bill, it shall inform the Customer in writing.
91. If the fact of error is confirmed or the error is revealed by the Distributor, then the correction shall be considered in the bill of the Customer for the current month.
92. If the electricity supply of the Customer is provided by the Supplier, then if errors are revealed in payment documents, the Parties shall be guided by conditions of the Supply Contract.

SECTION 4. RECALCULATION OF ELECTRICITY CONSUMPTION IN CASE OF IMPROPER OPERATION OF COMMERCIAL METERING DEVICES

CHAPTER 17. PROCEDURE ON RECALCULATION OF ELECTRICITY SUPPLIED IN CASE OF IMPROPER OPERATION OF A COMMERCIAL METERING DEVICE

93. In case of improper operation of a Commercial Metering device, the Distributor shall recalculate the quantity and the cost of electricity supplied.

94. In case of improper operation of a Commercial Meter, where the improper operation is not associated with the failure of voltage or current transformers and

1) If according to Provision 72 of these Rules, there is a Control Meter available, then recalculation of the quantity of electricity consumed shall be performed based on the control meter readings for the period starting the day of dismantling the Commercial Meter until the second to last reading of that meter. The recalculated quantity of electricity shall be determined by the following
formula:

$$REq = ConMEq + TL - ComMDEq$$

where:

REq – the quantity of electricity recalculated for the period of improper operation of the Commercial Metering device (kWh),
ConMEq – the quantity of electricity metered by the Control meter starting the day of the second to last reading of the control meter until the day of the dismantling of the Commercial Metering device (kWh),
TL – the amount of technological losses at electric installations located between the Commercial and Control meters for the period from the second to last reading of the Control meter until the day of the dismantling of the Commercial Metering device (kWh),
ComMEq – the quantity of electricity metered by the Commercial Meter from the moment of registration of the second to last reading of the Commercial Meter to the day of dismantling the Commercial Meter, and in case of sub-Customers, the portion of metered electricity attributed to the given sub-Customer (kWh).

2) If no Control meter is available there, but the quantity of electricity is metered by electronic meter and, as a result of calibration of the Commercial meter, a failure of the information display has been revealed, but the meter was operating within the range of errors and it was possible to derive data from the meter memory, then the quantity of electricity shall be determined by using data derived from the electronic meter memory and corresponding data registered as a result of the expert conclusion of the Metrology and Calibration Body.

3) If there is no control meter and, as a result of calibration of the Commercial Meter, it was impossible to derive data from the electronic meter memory, and if the Customer's meter is included in the electricity automated metering and control system and for monitoring purposes the Customer has been awarded the right of access to the memory platform of that system or the Customer was properly informed about such a right, then the recalculation shall be done as follows:

$$R_{Eq} = (Bd1 * Adc1 + NBd2 * Adc2) – ComMEq1$$

where:

Bd1 – the number of business days within the period of improper operation of the Commercial Metering device.
Adc1 – the average daily consumption of electricity over the 5 days preceding the failure of the Commercial Metering device.
NBd2 – the number of non-business days within the period of improper operation of the Commercial Metering device.
Adc2 – the average daily consumption of electricity of 2 non-business days preceding the failure of the Commercial Metering device.
ComMEq1 – the quantity of electricity (in kWh) recorded by the Commercial Metering device during improper operation and, in case of sub-Customers, the portion attributed to the given sub-Customer out of the total metered electricity.
The recalculated quantity, if it is a positive number, shall be added to and if it is a negative number, shall be subtracted from the quantity of electricity registered by the meter. If the period of improper operation exceeds 20 days, the recalculation shall be performed for 20 days starting at the moment of the discovery of the failure.

4) If there is no bi-directional (reversible) control meter and, as a result of calibration of the Commercial reversible meter, it was impossible to derive data from the electronic meter memory, and if the Customer's meter is included in the electricity automated metering and control system, and for monitoring purposes the Customer has been awarded the right of access to the memory platform of that system or the Customer was properly informed about such a right, then
   a) The recalculation of electricity injected into the network of the Autonomous Power Producer (APP) shall be done as follows:

$$R_{eq\,APP1} = (Bd1 * Adc3 + NBd2 * Adc4) – ComMEq3$$

where:
Adc3 – the average daily volume of electricity delivered to the APP network and consumed by the APP over the 5-day period preceding the failure of the Commercial Metering device.
Adc4 – the average daily volume of electricity delivered to the APP network and consumed by the APP over the 2 non-business days preceding the failure of the Commercial Metering.
ComMEq3 – the quantity of electricity (in kWh) recorded by the Commercial Meter during improper operation of the meter as consumption attributed to the given APP
The recalculated quantity, if it is a positive number, shall be added to and if it is a negative number, shall be subtracted from the quantity of electricity registered by the meter.
   b) The recalculation of electricity injected by the APP into the electricity system shall be calculated as follows:

$$R_{eq\,APP2} = (Bd1 * Adc5 + NBd2 * Adc6)– ComMEq4$$

where:

Adc5-the average daily volume of electricity injected into electricity system (including delivered to other Customers) over the 5 days preceding the failure of the Commercial Meter.
Adc6- the average daily volume of electricity injected into the electricity system (including delivered to other Customers) over 2 non-business days preceding the failure of the Commercial Meter.
ComMEq4-the quantity of electricity (in kWh) injected into the electricity system (including that delivered to other Customers) during improper operation of the meter and registered based on the Commercial Meter readings.

The recalculated quantity, if it is a positive number, shall be added to and if it is a negative number, shall be subtracted from the quantity of electricity registered by the meter.
If the period of improper operation exceeds 20 days, the recalculation shall be performed for 20 days starting from the moment of the discovery of the failure.

If the improper operation of the Commercial Meter took place within 7 days after the date that the Electricity Supply and Compensation Contract (between APP and Distributor) entered into effect, then the average daily quantity of electricity injected into the APP's network and the electricity system shall be calculated based on the corresponding records on consumption and/or delivery of electricity during the 7 days following the restoration of the meter.

5) If there is no control meter and, as a result of calibration of the Commercial meter, it is impossible to derive data from the electronic meter memory, and if the Customer's Commercial Meter is not included in the automated metering and control system, but following the expert conclusion of the Metrology and Calibration Body, it is possible to determine the percentage of registration error of the Commercial Meter, then the recalculation shall be done as follows:

$$REq = \frac{ComMEq2 \,.\, E\%C}{100\%}$$

for cases when the Commercial Metering device operated slower than its permissible range of error, and

$$REq = - \frac{ComMEq2 \,.\, E\%C}{100\%+E\%C}$$

for cases when the Commercial Meter operated faster than its permissible range of error,
where:
ComMEq2 – the quantity of electricity metered by the Commercial Meter from the moment the second to last reading is recorded until the day the Commercial meter is dismantled (kWh),
E%C – the percentage of the error exceeding the permissible range of metering error of the Commercial Meter stated in the expert conclusion of the Metrology and Calibration Body, which most accurately describes the value of the power factor (cos ϕ) and of the current load of the Customer's consumption system over the month preceding the disclosure of improper operation.

6) If there is no control meter and, as a result of calibration of the Commercial Meter, it was impossible to derive data from the electronic meter memory, and if the Customer's meter is not included in the automated metering and control system , and at the same time metrology and calibration body concluded that the meter was not subject to inspection or it was impossible to determine the percentage of registration error of the Commercial Meter, then the recalculation shall be done as follows:

$$RE_q = Com_{Pd} \cdot P_{adc} - ComM_{Eq}$$

where:
P_{adc} – the average daily consumption of the same month of the year preceding the dismantling of the Commercial Metering device multiplied by the quotient of the consumption for 3 months preceding the improper operation and the consumption of the same period of the previous year. Where the Customer did not consume electricity in any month throughout the 3 months before improper operation and the same period of the previous year, then the value of P_{adc} shall be accepted as equal to the average daily consumption of the same month of the year preceding the year of improper operation of the Commercial Meter. Where the Customer did not consume electricity during the same month of the previous year, then the average daily consumption shall be accepted as equal to the average daily consumption of the first month in which the Customer consumed electricity following the restoration of Commercial Meter operation.
Com_{Pd} – the period between the day of recording the second to last reading of the Commercial Meter and the day
of dismantling of the Commercial Meter, in a number of days that shall be accepted as equal to 60 if the period exceeded 60 days; this does not restrict the Distributor's right to apply a shorter period if proper justifications are available.

7) If there is no bi-directional (reversible) control meter and, as a result of calibration of the Commercial reversible meter, it is impossible to derive data from the electronic meter memory and at the same time the Metrology and Calibration Body concluded that the meter was not subject to inspection or that it was impossible to determine the percentage of registration error of the Commercial

Meter, then the recalculation shall be done as follows:

$$RE_{eqr} = P_{adp} \cdot Com_{dr} - ComM_{r},$$

where:

RE_{eq} – quantity of electricity (power flow exchange) recalculated for the period of improper operation of the Commercial Reversible Meter of the APP (kWh), which is calculated separately for daytime and nighttime power flows and is considered in the act on electricity subject to compensation (payment).

P_{adp} – the average daily difference of power flows exchanged based on the results of the Distributor and the APP for the same month of the previous year, which shall be positive if the APP's consumption exceeds the electricity delivered to the Distributor and shall be negative if electricity delivered to the Distributor exceeds the consumption of the APP.

Com_{dr} – the period between the day of recording the second to last reading of the Commercial Reversible Meter and the day of the dismantling of that meter, in days, which shall be accepted equal to 33, if the period exceeded

33 days.

$ComM_{r}$ – the difference between power flows recorded based on the readings of the Commercial Reversible Meter (daytime, nighttime) over the period of improper operation of the meter, and in case of sub-Customers available, the portion of metered electricity attributed to the given sub-Customer.

Where the APP did not consume or deliver electricity during the same month of the previous year, then the average daily difference of power flow exchange shall be accepted as equal to the average daily consumption of the month in which the APP consumed or delivered electricity for the first time after the restoration of the Commercial Meter operation.

95. In case of failure of a Commercial Metering device, when the failure is conditioned by improper operation of the current or voltage transformers and there is a control meter available, then electricity shall be recalculated according to sub-Provision 1) of Provision 98 of the Rules. If there is no control meter and if the Commercial Metering device:

1) Recorded an erroneous quantity of consumed electricity due to the failure of the voltage transformer, and the Commercial Metering device attributed to the given Customer is included in the automated metering and control system and for monitoring purposes the Customer has been awarded the right of access to the memory platform of that system or the Customer was properly informed about such a right, then the recalculation shall be done according to sub-Provision 3 of Provision 94 of these Rules. In instances when the Commercial Metering device is not included in the automated metering and control system, the recalculation shall be performed according to sub-Provision 6 of Provision 94 of these Rules.

2) Recorded an erroneous quantity of consumed electricity due to the failure of the current transformer, then for each current transformer, the following formulas shall be used when the current transformation error is beyond the negative permissible range:

$$REq = \frac{ComMEq \cdot E\%CT}{n100\%}$$

For cases when the current transformation error is beyond the positive permissible range:

$$REq = - \frac{ComMEq \cdot E\%CT}{n \cdot 100\% + E\%CT}$$

where:

E%CT – the percentage value of the error exceeding the permissible range of error of the current transformer of the Commercial Metering device specified in the expert conclusion provided by the Metrology and Calibration Body, which most accurately describes the current load over the month preceding the disclosure

of improper operation.

n – the number of current transformers involved in the metering process. The aggregate quantity of recalculated electricity consumption shall be accepted as equal to the sum of recalculation results for all current transformers.

96. In case of failure of APPs' reversible commercial metering devices, if the failure is caused by the malfunction of the current or voltage transformers, the recalculation shall be performed in accordance with Provision 94(7) of the REM Rules.
97. In cases of failure of a Commercial Meter, the recalculated cost of electricity shall be determined as a product of recalculated quantities differentiated by day and night and the appropriate tariff for the month when the Commercial Meter failure was revealed. If differentiation of electricity by day and night is not possible, then the cost of recalculated electricity shall be determined as a product of recalculated electricity and average weighted tariff formed in the month preceding the disclosure of improper operation.
98. In the case of revealing the fact of failure of a Commercial Metering device, when the Distributor has well-grounded proofs that the failure has been caused by a Customer's actions (including, but not restricted to cases when the seals of Commercial Metering devices are removed, tampered with, or damaged or another interference is disclosed), the Distributor shall have the right to request that the Customer pay a penalty of 5 times the cost of the recalculated electricity. If there is no objection by the Customer as to the requirement of the Distributor to pay the penalty, the Distributor shall include the calculated amount of penalty in the Customer's bill for the next Settlement month following the fulfillment of recalculated liabilities. In case of objections, the Customer shall solve the issue in court. The Distributor shall not suspend the Customer's electricity supply for non-payment of its debts until the final resolution of the issue.
99. In case of a failure of a Commercial Metering device, when the Customer has well-grounded proofs that the failure has been caused by the Distributor's actions (including, but not restricted to cases when the seals of Commercial Metering devices are removed, tampered with, or damaged or another interference is disclosed), the Customer shall have the right to request that the Distributor pay a penalty at 5 times the cost of the recalculated electricity. If there is no objection by the Distributor to the Customer's requirement to pay the penalty, the Distributor shall include the calculated amount of penalty in the Customer's bill for the next Settlement month following the fulfillment of recalculated liabilities. In case of an objection, the Customer shall resolve the issue in court.
100. In case of complaints by the Customer concerning the results of recalculation, within 7 business days of receiving the complaints, the Distributor shall be obliged to discuss the complaints and inform the Customer in writing about the disputable issues and their grounds. Where inaccuracies are revealed in the recalculations, the Distributor shall be obliged to correct the cost of the recalculated electricity. Where the results of recalculation create disagreement between the Customer and the Distributor, the Customer, along with the cost of electricity for the next Settlement month from the recalculation, shall also pay for the part of electricity that it considers non-disputable. In such instances, the Distributor shall not be eligible to suspend the Customer's service until the final resolution of the dispute under procedures defined by the REM Rules.
101. To balance the interests of the Customer and the Distributor, the Commission, in certain individual cases stipulated by consumption specifics, may make individual decisions on the recalculation of outstanding liabilities based on the application of the Supplier or the other applicant (with corresponding argumentation attached).
102. Damages associated with improper operation of Commercial Metering devices shall be regulated in legally defined procedures.

SECTION 5. PENALTIES IMPOSED ON THE DISTRIBUTOR

CHAPTER 18. PENALTIES IMPOSED ON THE DISTRIBUTOR FOR VIOLATION OF REQUIREMENTS OF THE RULES

103. The Distributor shall pay a penalty to the Customer:

1) If it is confirmed that in the Customer's payment document the specified quantity of electricity exceeds the Customer's actual consumption;
2) For each case of violation of procedures specified in the REM Rules on correction of errors in the payment documents;
3) For each case of violation of procedures or the period specified in the REM Rules for recalculation of electricity consumed;
4) For each case of violation of procedures or the period defined in the REM Rules for the conclusion, modification, or termination of the Contract;
5) For each case of violation of procedures or the period defined by the REM Rules for answering the Customer's complaint.

104. In cases mentioned in Provision 103 of the REM Rules, the Distributor shall pay a penalty in the amount of 50 percent of the average monthly cost of electricity consumed, not exceeding 2,500 AMD, and in case of zero consumption, it should be 2,500 AMD.

105. The estimated penalty shall be considered by the Distributor in the calculation of the Customer's bill for the current month. The estimated penalty shall be recorded in the bill as a separate line and be subtracted from the cost of electricity supplied, and in the case of a Supplier's Customer, from the cost of distribution services.

106. The Distributor shall not be charged a penalty for the violations specified in Provision 103 of these Rules if those are affected by a force majeure situation.

SECTION 6. TRANSITIONAL PROVISIONS

107. Those Customers (except for residential customers) that hold electricity Supply Contracts with the Universal Supplier shall acquire Qualified Customer status in accordance with the WEM Rules or choose a Supplier (if available) in accordance with the REM Rules within the following timeframes:
    1) Customers connected to the Transmission Network or Generator, as well as 110 kV and higher voltage Customers that in the previous calendar year had 1 million kWh or more consumption recorded through all their Commercial Metering devices – before February 1, 2023;
    2) 35 kV voltage Customers that in the previous calendar year, across all their Commercial Metering devices, had annual consumption of 1 million kWh or more – before February 1, 2024;
    3) 6(10) kV voltage Customers that in the previous calendar year, across all their Metering points, had annual consumption of 1 million kWh or more – before February 1, 2025;
    4) Customers that in the previous calendar year, across all their Metering points, regardless of the voltage level, had annual consumption of 1 million kWh or more – before February 1, 2025.
108. In cases when a Supplier is not chosen or a Qualified Customer's status is not obtained in accordance with the timeframes specified in Provision 107 of the REM Rules, such Customers shall pay the Universal Supplier for electricity consumed at the tariff set by the Commission in accordance with Provision 82 of the REM Rules.
109. The requirements of Provision 107 of the REM Rules shall not restrict the Customers' right to obtain Qualified Customer status as prescribed by WEM Rules or to choose a Supplier as prescribed by the REM Rules starting February 1, 2022.

ANNEX 1. PROCEDURE ON THE TRANSFER OF ELECTRICITY THROUGH ELECTRIC INSTALLATIONS OF THE CUSTOMER TO FEED THE NETWORKS OF SUB-CUSTOMERS OR OTHER NETWORKS OF THE DISTRIBUTOR

1. This procedure shall regulate the relationship within the framework of transferring electricity through electric installations of the Customer to feed the networks of Sub-Customers or other networks of the Distributor, as well as calculating the cost of service provided by the Customer through its electric installations to feed the networks of Sub-Customers and other networks of the Distributor.
2. The Customer shall be obliged to transfer electricity through its electric installations to feed the networks of Sub-Customers and other networks of the Distributor.
3. The relationship between Customers, Sub-Customers, and the Distributor shall be regulated by the Energy Law, these Procedures, rules for supply and use of electricity, the Contract signed between the Customer and the Distributor (hereinafter, refer to as the Compensation Contract), and other legal acts.
4. The Customer shall be responsible for keeping its electric installations in proper condition, to carry out renovation at its own expense, and to bear the maintenance costs.
5. The Customer shall have the right to transfer its own electricity to another entity if such a transfer is not a separate type of entrepreneurship and proceeds from the specifics of the Customer activity (provision of commercial, industrial, and residential spaces for utilization).
6. The Compensation Contract shall be concluded in a written form and for an uncertain period.
7. The data on a Sub-Customer that is connected to the energy installations of the Customer (name, surname, location (residence), location of the consumption system, manufacturer number and technical indicators of Commercial and Control Meters, and the maximum allowed electric capacity) shall be specified in or attached to the Compensation Contract.
8. According to the Compensation Contract, the Distributor shall be required to pay the monthly amount of service charges of the Customer calculated as defined in this Procedure (hereinafter, referred to as the Service Charge).

9. In case of a requirement to alienate the energy facilities of the Customer having been used for electricity supply of the Sub-Customer or other networks of the Distributor, the Customer shall inform the Distributor 3 months in advance.
10. In case of modifying the parameters of or changing the location of its energy installations, the Customer shall be required to inform the Distributor 3 months in advance. The planned changes shall comply with the requirements of technical regulations.
11. In cases requiring notification and/or submission of documents defined in this Procedure, the notification and/or submission shall be performed in an appropriate manner.
12. Notification and submission of documents shall be deemed appropriately performed if the information has been sent by registered letter with a notice of delivery or other means securing the integrity of the message (including sending a message to a phone number specified by the applicant), or by electronic communication systems (including to the email address specified by the applicant), as well as through other electronic communication means defined by legislation, or it has been handed over with a mail delivery confirmation, unless otherwise specifically mentioned in these Rules.
13. The charge for services rendered by the Customer to feed the networks of the Sub-Customer or other networks of the Distributor shall be calculated by the following formula:

$$C=A+K$$

where:
C – the service charge (AMD/month without VAT),
A – the amount of additional costs necessary to maintain the energy installations of the Customer that are used to feed the Sub-Customers or other networks of the Distributor (AMD/month)
K – the monthly amount of compensation for the losses occurring in the transformer and lines of the Customer while feeding the Sub-Customers or other networks of the Distributor.

14. The amount of additional costs of maintenance of energy installations of the Customer that are used to feed the Sub-Customers and other networks of the Distributor shall be calculated by the following formula:

$$A = a_1 (n_1 + n_1/2) + a_2 (n_2 + n_2/2) + W_{Sub} (a_3 + a_4 + a_5 + a_6 + a_7)$$

where:
a_1 – the service charge for the use of one cell with the purpose of its operation, to be paid to the Customer.

n_1 – the total number of cells at 110 kV, 35 kV, and 6(10) kV voltage substations, used to ensure electricity supply of other Customers only.

n_2 – the total number of cells at 110 kV, 35 kV and 6(10) kV voltage substations jointly used to ensure electricity supply of the Customer, Sub-Customer, or other networks of the Distributor.

a_2 – the service charge to be paid to the Customer for the use of one connection point with the purpose of its operation.

n_3 – the number of connection points out of 0.4 (0.23) kV connection points that are used to ensure electricity supply only for Sub-Customers or other networks of the Distributor.

n_4 – the number of connection points out of 0.4 (0.23) kV connection points that are jointly used to ensure electricity supply of the Customer, Sub-Customer, or other networks of the Distributor.

W_{Sub} – the monthly amount of electricity (kWh) transferred by the Customer to Sub-Customers or other networks of the Distributor metered by Commercial metering devices of the Sub-Customer or Customer.

a_3 – the service charge for transformation of 1 kWh of energy at 110 kV substations aimed at operation of the Customers' transformers.

a_4 – the service charge for transformation of 1 kWh of energy at 35 kV substations aimed at operation of

the Customers' transformers.

a_5 – the service charge for transformation of 1 kWh of energy at 6(10) kV substations, aimed at operation of the Customers' transformers.

a_6 – the service charge for transfer of 1 kWh aimed at operation of 6(10) kV transmission lines of the Customer.

a_7 – the service charge for transfer of 1 kWh aimed at operation of 35 and 110 kV transmission lines of the Customer.

15. The amounts of service charges from a_1 to a_7 specified in Provision 15 of this Procedure shall be equal to the values stated in Table 1 below:

Table N1

(without VAT)

N	Value	Service charge
1	a_1	7,930 AMD/month
2	a_2	430 AMD/month
3	a_3	0.796 AMD/month
4	a_4	1,426 AMD/month
5	a_5	1,602 AMD/month
6	a_6	0.768 AMD/month
7	a_7	1,363 AM/kWh

16. If more than one substation or transmission line is utilized to supply electricity to Sub-Customers or other networks of the Distributor through the energy installations of the Customer, the value "A" specified in this Procedure shall be calculated separately for each substation or each transmission line, and if this value exceeds the marginal values specified in Table 1 of this Provision, then it is accepted as equal to the values stated in Table 1 of this Provision.

Table N1

AMD/month (without VAT)

N	Voltage of Customer's consumption system	Marginal values of costs of operation of the Customer's substations subject to compensation	Marginal values of costs of operation of the Customer's transmission lines subject to compensation
1	6(10) kV	89,217	16,522
2	35 kV	356,867	28,087
3	110 kV	713,734	29,739

17. The amount to compensate the losses that occur at transformers and electricity transmission lines as a result of providing electricity supply to Sub-Customers or other networks of the Distributor,

expressed as K, shall be considered in the formula if these losses are included in electricity subject to payment by the Customer. K shall be calculated as follows:

$$K = W_{SUB} \; T \; (a_8 + a_9)/(100 - a_8 - a_9)$$

where:

T – the electricity tariff for the Customer (daytime, AMD/kWh, without VAT).

a_8 – losses at the transformers (in percentage terms), which are accepted as equal to 1.3 if the Customer is supplied from the 6 kV and over network.

a_9 – losses at the transmission lines (in percentage terms), which are accepted as equal to 1 if Sub-Customers or other networks of the Distributor are supplied from 6 kV and over networks, and equal to 3 if Sub-Customers or other networks of the Distributor are supplied from 0.4 and lower networks.

18. Each year before December 1, the Commission shall review the monetary values mentioned in this Procedure, applying the Customer price indexes for September of the current year towards the indexes for the same month of the previous year. The values determined as a result of the revision shall become effective from January 1 of the year after the current year.

ANNEX 2. PROCEDURE ON PROVIDING REIMBURSEMENT FOR ELECTRICITY SUPPLIED BY THE DISTRIBUTOR AND AUTONOMOUS POWER PRODUCERS USING RENEWABLE ENERGY RESOURCES

1. This Annex defines the procedure on providing reimbursement for electricity supplied under renewable energy (RE) flows between Autonomous Power Producers using Renewable energy resources (hereinafter, RES APPs) and the Distributor in the electricity system.
2. The calculation of amounts subject to payment for electricity supplied by RES APPs to the Distributor shall be made on a monthly basis and the final balance settlement on a yearly basis. Within the framework of the RE flows, the Settlement year is the period from January 1 of each year to December 31, inclusive.
3. The RES APPs shall have reverse multi-tariff electronic meters installed at their premises. Procedures on the purchase and maintenance of such meters shall be regulated by the Distribution Network Code and other legal acts of the Commission.
4. The supply of electricity from the RES APPs to the Distributor and reimbursement for the supplied electricity shall be implemented based on the electricity supply and reimbursement contract signed between the RES APP and the Distributor in compliance with the model contract approved by the Commission.
5. Relations in respect to a new connection of the RES APP to the electric networks shall be regulated by the Distribution Network Code, the Rules, and other legal acts of the Commission.
6. The electricity balance calculation between the RES APP and the Distributor for the Settlement period shall be implemented by the following formula:

$$E_{FDi} = E_{FD(i-1)} + (US_{Di} - A_{Di})$$

$$E_{FNi} = E_{FN(i-1)} + (US_{Ni} - A_{Ni})$$

where:

E_{FDi} – the result of electricity balance calculation for the period of the i^{th} Settlement month defined for the daytime tariff.

$E_{FD(i-1)}$ – the result of the electricity balance calculation for the period in the $(i-1)^{th}$ Settlement month defined for the daytime tariff.

US_{Di} – the quantity of electricity supplied by the Distributor to the RES APP at the daytime tariff within the i^{th} Settlement month.

A^{Di} – the quantity of electricity supplied by the RES APP to the Distributor during the period in the i^{th} Settlement month defined for daytime tariff.

i – Settlement months of the Settlement year.

E_{FNi} – the result of electricity balance calculation for the period in the i^{th} Settlement month that is defined for the nighttime tariff.

$E_{FN(i-1)}$ – the result of electricity balance calculation for the period in the $(i-1)^{th}$ Settlement month that is defined for the nighttime tariff.

US_{Ni} – the quantity of electricity supplied by the Distributor to the RES APP at the nighttime tariff within the i^{th} Settlement month.

A_{Ni} – the quantity of electricity supplied by the RES APP to the Distributor during the period of the i^{th} Settlement month defined for the nighttime tariff.

7. For the first Settlement month of each settlement year, the values of $E_{FD(i-1)}$ and $E_{FN(i-1)}$ shall be accepted as equal to zero. The values of $E_{FD(i-1)}$ and $E_{FN(i-1)}$ shall also be accepted as equal to zero if they have a positive sign.
8. For the Settlement month, when E_{FDi} is positive, that amount of electricity shall be considered to be supplied at the daytime tariff from the Distributor to the RES APP (as a Customer). The dates for submitting the payment document and making payments shall be regulated by the Contract between the parties and the REM Rules.
9. For the Settlement period, when E_{FNi} is positive, that amount of electricity shall be considered to be supplied at the nighttime tariff from the Universal Supplier to the RES APP (as a Customer) and the dates for submitting the payment document and making payments shall be regulated by the Contract between the parties and the Rules.
10. The amount of electricity subject to payment by the RES APPs within the settlement year shall be calculated by the following formula:

$$E_{PD} = \sum_{i=1}^{12} E_{FDi}$$

$$E_{PN} = \sum_{i=1}^{12} E_{FNi}$$

where:

E_{PD} – the grand total of all positive values of E_{FDi} in all Settlement months of the settlement year,

E_{PN} – the grand total of all positive values of E_{FNi} in all Settlement months of the settlement year.

11. The amount of RE flows between the Universal Supplier and RES APPs during the settlement year shall be calculated as follows:

$$E_{Dif} = E_D + E_N$$

where:

1) E_{Dif} is the difference in RE flows between the Distributor and the RES APP during the settlement year

2) E_D is the difference in the daytime RE flows between the Distributor and the RES APP during the settlement year that is calculated as follows:

$$E_D = \sum_{i=1}^{12} (US_{Di} - A_{Di}),$$

where:

1) E_N is the difference in the nighttime RE flows between the Distributor and the RES APP during the settlement year that is calculated as follows:

$$E_N = \sum_{i=1}^{12} (US_{Ni} - A_{Ni}),$$

12. The quantity of and payment for electricity subject to reimbursement by the Distributor to the RES APP shall be calculated as follows:

1) Where $E_{Dif} > 0$ and at the same time $E_D > 0$, $E_N > 0$, $E_D = E_{PD}$ and $E_N = E_{PN}$, no reimbursement shall be made to the RES APP;

2) Where $E_{Dif} > 0$ and at the same time $E_D > 0$, $E_N > 0$, $E_D < E_{PD}$ and $E_N = E_{PN}$, the quantity of electricity subject to reimbursement shall make $(E_{PD} - E_D)$ and the amounts paid for that quantity (including VAT) shall be returned to RES APPs. The calculation shall be implemented at the beginning of the settlement year increasingly until the given amount is covered.

3) Where $E_{Dif} > 0$ and at the same time $E_D > 0$, $E_N > 0$, $E_D = E_{PD}$ and $E_N < E_{PN}$, the quantity of electricity subject to reimbursement shall make $(E_{PN} - E_N)$ and the amounts paid for that quantity (including VAT) shall be returned to RES APPs. The calculation shall be implemented at the beginning of the settlement year increasingly until the given amount is covered.

4) Where $E_{Dif} > 0$ and at the same time $E_D > 0$, $E_N > 0$, $E_D < E_{PD}$, and $E_N < E_{PN}$, the quantity of electricity subject to reimbursement shall be the sum of $(E_{PD} - E_D)$ and $(E_{PN} - E_N)$ and the amounts paid for that quantity of electricity (including VAT) shall be returned to RES APPs. The calculation shall be implemented at the beginning of the settlement year increasingly until the given amount is covered.

5) Where E_{Dif} >0 and at the same time E_D <0 and E_N >0, the amounts paid for E_{PD} quantity of electricity (including VAT) shall be returned to RES APPs. From the quantity of electricity consumed during nighttime hours, the quantity of electricity ($E_{PN} – E_{Dif}$) shall be reimbursed and the amounts paid for that quantity (including VAT) shall be returned to RES APPs. The calculation shall be implemented at the beginning of the settlement year increasingly until the given amount is covered.

6) Where E_{Dif} >0 and at the same time E_D >0 and E_N <0, the amounts paid for E_{PN} quantity of electricity (including VAT) shall be returned to RES APPs. From the quantity of electricity consumed during daytime hours, the quantity of electricity ($E_{PD} – E_{Dif}$) shall be reimbursed and the amounts paid for that quantity (including VAT) shall be returned to RES APPs. The calculation shall be implemented at the beginning of the settlement year increasingly until the given amount is covered.

7) Where E_{Dif} <0 and at the same time E_D <0 and E_N >0, the amounts paid for E_{PN} and E_{PD} (including VAT) shall be returned to RES APPs. At the same time, the amount of electricity equal to the absolute value of E_{Dif} shall be reimbursed to the RES APPs at a tariff equal to 50 percent of the daytime tariff set by the Commission for the given Customer group for each Settlement month of the settlement year, except for the following cases:
   a. For Small HPPs, the current tariff set by the Commission for the given Customer group (run-of-river, irrigation system, and drinking water system) shall be applied;
   b. For power plants generating from solar or wind energy sources, the lowest tariff out of the current tariffs set by the Commission for industry-scale solar power plants shall be applied if the latter is less than 50 percent of the daytime tariff set by the Commission for the given Customer group.

8) Where E_{Dif} <0 and at the same time E_D >0 and E_N <0, the amounts paid for E_{PN} and E_{PD} (including VAT) shall be returned to the RES APPs. At the same time, the amount of electricity equal to the absolute value of E_{Dif} shall be reimbursed to the RES APPs at a tariff equal to 50 percent of the nighttime tariff set by the Commission for the given Customer group for each Settlement month of the settlement year, except for the following cases:
   a. For Small HPPs, the current tariff set by the Commission for the given Customer group (run-of-river, irrigation system, and drinking water system) shall be applied;
   b. For power plants generating from solar or wind energy sources, the lowest tariff out of the current tariffs set by the Commission for industry-scale solar power plants shall be applied if the latter is less than 50 percent of the nighttime tariff set by the Commission for the given Customer group.

9) Where E_{Dif} <0 and at the same time E_D <0 and E_N <0, the amounts paid for E_{PN} and E_{PD} (including VAT) shall be returned to the RES APPs. At the same time, the amount of electricity equal to the absolute value of E_D and E_N shall be reimbursed to the RES APPs at a tariff equal to 50 percent of the daytime tariff and nighttime tariff, respectively, set by the Commission for the given Customer group for each Settlement month of the settlement year, except for the following cases:
   a. For Small HPPs, the current tariff set by the Commission for the given Customer group (run-of-river, irrigation system, and drinking water system) shall be applied;
   b. For power plants generating from solar or wind energy sources, the lowest tariff out of the current tariffs set by the Commission for the industry-scale solar power plants shall be applied if the latter is less than 50 percent of the daytime tariff and nighttime tariff, respectively, set by the Commission for the given Customer group.

13. After the end of the calendar year, before January 25 of the following year, the Distributor and the RES APP shall prepare a reconciliation document in accordance with the legislation of the RoA to obtain reimbursement from the Distributor. Based on the reconciliation document, the Distributor shall transfer the reimbursement amount to the bank account of the RES APP before March 1 of the year following the settlement year.

CONNECTION OF CONSUMPTION SYSTEM TO ELECTRIC NETWORK, DISTRIBUTION OF ELECTRICITY, AND UNIVERSAL SUPPLY OF ELECTRICITY CONTRACT

_____ _____20__

(Location)

Distributor _____
(Universal Supplier) (name, location)

represented by _____,
(name, surname, position, letter of authorization data)

on the one hand,

and Customer _____,
(name, surname, passport or ID number, in case of a legal entity - company or organization name, name and surname and position of the representative; in case of an authorized person – the authorization data)

on the other hand, collectively known as the Parties, being guided by the Energy Law and other laws, the Electricity Retail Market Trading Rules (hereinafter, referred to as REM Rules), and the Electricity Distribution Network Code (hereinafter, referred to as EDN Code) approved by the RoA Public Services Regulatory Commission (hereinafter, the Commission), as well as the and other legal acts, have concluded this Contract (hereinafter, the Contract) on the following:

1. SUBJECT OF THE CONTRACT

1. Under this Contract, the Distributor shall connect the newly constructed or reconstructed consumption system of the Customer for
   ☐ household
   ☐ non-household
   purposes, located at _____ (hereinafter, the Consumption System) to the electric network (hereinafter, the Connection) and provide to the Customer distribution service of electricity purchased by the latter from the Supplier; it shall also provide universal supply of electricity, whereas the Customer shall pay for the Connection (except for the cases defined in the EDN Code), the electricity distribution services provided to him/her, and universal supply.

2. ELECTRIC NETWORK CONNECTION PROCEDURE

2. The Connection Charge for connecting the Customer's Consumption System (hereinafter, the Connection Charge) shall amount to _____AMD including VAT, as outlined in Annex 1 to this Contract.
3. Within 24 months from the conclusion of this Contract, the Customer shall transfer 50 percent of the Connection Charge (hereinafter, the Advance Amount) to the Distributor's bank account identified for payment of the Connection Charge specified in the prerequisites of this Contract.

4. The Distributor shall ensure implementation of the connection to the electric network within ___ days following the payment of the Advance Amount or, in case of a simplified connection procedure, as defined in the EDN Code for 0.22 kV or 0.4 kV Customers within _____ days (these periods shall not exceed the periods defined in the EDN Code).
5. In the case of a complex connection procedure, as defined in EDN Code, the connection shall be carried out based on Technical Conditions specified in Annex 2 of this Contract and/or according to a single line electricity supply diagram defined in Annex 3 of this Contract.
6. The difference between the entire amount of the Connection Charge and the prepaid Advance Amount shall be paid by the Customer to the Distributor during the month following the connection within the period defined by the REM Rules for payment of charges for electricity consumed, based on the payment document issued by the Distributor for the purposes of connection.
7. Where the Customer fails to fulfill its payment obligation per Provision 6, the Customer's electricity supply may be suspended in procedures defined by the REM Rules.

3. BASIC RIGHTS AND OBLIGATIONS OF PARTIES IN THE CONTEXT OF ELECTRIC NETWORK CONNECTION RELATIONSHIPS

8. Distributor's obligations:
   1) To ensure the connection of the Customer's consumption system to the electric network according to Provisions 4 and 5;
   2)If the Customer did not ensure receipt of electricity according to Provision 10(2) of the Contract, to connect the consumption system of the Customer to the electric network within 3 business days after having been informed of the readiness of the Customer to receive electricity;
   3) In cases and procedures provided for by Provision 11(1) of this Contract and by the EDN Code, to return the Advance Amount to the Customerin the form preferred by the latter (cash or non-cash);
   4) In case of changes in the connection dates, to inform the Customer in a transparent manner within 3 business days after the Distributor becomes aware of the change;
   5) To pay a penalty to the Customer for violation of connection periods defined in this Contract pursuant to Provision 31 of this Contract.
9. Distributor's rights:
   1) To demand that the Customer pay the difference between the Connection Charge and the Advance Amount within the period defined in Provision 6 of this Contract;
   2) Where the Customer violates the obligation defined in Provision 6 of this Contract, to suspend the universal supply of the Customer in procedures defined by the EDN Code or to calculate the penalty in accordance with Provision 32 of this Contract and the EDN Code.
10. Customer shall be obliged:
   1) To pay the Advance Amount, as well as the difference between the Connection Charge and the Advance Amount according to Provision 6 of the Contract, except for the cases defined in the EDN Code,
   2) To enable the receipt of services within the period defined in Provision 4 of the Contract, and where this period is not adhered to, to inform the Distributor about the date of Customer readiness to receive electricity.
11. Customer shall be eligible:
   1) To request in written form that the Distributor return the Advance Amount in 5 business days after the payment is made. Once the period is expired, the Advance Amount shall be subject to return only on condition that the actual expenses incurred by the Distributor for implementation of works on the connection of the Customer's consumption system to the electric network according to this Contract will be compensated within 5 business days upon submission of the request for return;

2) Where the dates specified in this Contract are violated, to impose a penalty on the Distributor in procedures defined by Provision 31 of the Contract.

4. BASIC RIGHTS AND OBLIGATIONS OF PARTIES IN THE CONTEXT OF ELECTRICITY DISTRIBUTION AND UNIVERSAL SUPPLY RELATIONSHIPS

12. According to this Contract, the Parties shall have all the rights and obligations that are defined in the REM Rules and EDN Code.

5. PRICE, QUANTITY, AND COST CALCULATION, PAYMENT PROCEDURE FOR DISTRIBUTION SERVICES PROVIDED AND ELECTRICITY SUPPLIED

13. The quantity of electricity consumed during the Settlement month shall be calculated in procedures defined by the REM Rules.
14. The price of electricity consumed by the Customer during the settlement month shall be calculated as the product of the tariff defined by the Commission and the quantity of electricity consumed, except for the cases specified in Provision 15 of this Contract. Where the tariff is changed by the Commission, the new tariff shall become effective from the day defined by the Commission. The cost of electricity supplied to the Customer during the settlement month shall be computed as a product of the Tariffs set forth by the Commission for the given voltage level and the given timeframe (if the Commercial Meter is capable of differentiated calculation) and the energy quantity supplied, except for cases defined in Provision 15 of this Contract, and in the case of the Supplier's Customer, the cost of distribution services rendered shall be determined as a product of the distribution service tariff set forth by the Commission for the given voltage level and the quantity of distributed electricity.
15. To restore the Customer's electricity supply by the Universal Supplier in cases prescribed by the REM Rules, as well as in cases when no Qualified Customer status is obtained or no Supplier is selected in terms and procedures defined by the REM Rules and WEM Rules approved by the Commission, the cost of electricity supplied to the Customer by the Universal Supplier within the Settlement month shall be calculated as a product of the tariff set forth by the Commission for the given Customer group and the quantity of electricity supplied.
16. In case of a change in the electricity tariff set forth by the Commission, the new tariff shall become effective from the date defined by the Commission.
17. The Customer shall, according to the REM Rules, pay the cost of electricity supplied or, in the case of the Supplier's Customer, the cost of distribution services provided during the previous month to the bank account of the Distributor mentioned in the Contract prerequisites once the billing document is submitted by the Distributor (personally or by authorized representative) in terms and procedures defined in the REM Rules.
18. Where errors have been discovered in the billing document, the party that discovered the error shall inform the other party. In case of disagreement, the relevant party shall provide clarifications supported by appropriate justifications in writing within timeframes defined by the REM Rules. Once the fact of erroneous calculation is confirmed, the Distributor shall consider the recalculated amount in the payment document for the next month.
19. In case of calculation of penalties in compliance with the REM Rules, the Distributor shall first redeem the cost of electricity supplied or, in the case of the Supplier's Customer, the cost of distribution service rendered starting from the previously incurred indebtedness and only then shall cover financial liabilities under the calculated penalties.
20. If there are outstanding financial liabilities, the Distributor shall not suspend the Customer's electricity supply on condition that the latter presents payment guarantees acceptable to the Distributor or develops with the Distributor a debt repayment schedule. This Provision shall not restrict the

Distributor's right to suspend the Customer's supply in case of violation of the repayment schedule, ensuring compliance with the procedures on suspension of electricity supply of the given Customer as prescribed in the REM Rules and EDN Code.

21. If there are no outstanding liabilities to the Distributor, payments by the Customer shall be used as deposit amounts to cover future liabilities if the Customer did not demand the amounts back.

6. VALIDITY OF CONTRACT

22. Provisions defined in this Contract with respect to connection to the electric network shall enter into force from the moment of signing this Contract and shall be valid until all obligations of parties associated with the connection of the consumption system to the electric network stated in Provision 1 of this Contract are completely fulfilled.
23. Provisions of this Contract with respect to distribution and/or universal supply of electricity shall enter into effect from the moment of the first actual connection of the Customer to the electric network, and for the reconstructed consumption system, from the moment of signing the Contract, and shall remain in effect for _____.
24. The Contract shall be signed for an uncertain period, except for the cases defined in the REM Rules. Where the given case requires concluding a temporary contract according to the REM Rules, 1 month before the expiration of the temporary contract's validity period, each party to the contract may notify the other party of the termination of the contract. If, after the expiration of the validity period, the Distributor has not provided a notification and the Customer continues consuming electricity, the Contract validity period shall be considered extended on the same terms and for the same period as the original temporary contract, except in cases prescribed by the REM Rules.
25. In cases when the Commission approves a new model form of the Contract on connecting the consumption system to the electric network or providing electricity distribution services and electricity universal supply, or introduces amendments or supplements thereto, the signed contracts shall be deemed new or shall be deemed signed or modified in compliance with the introduced changes starting on the date of effectiveness of the corresponding legal act.
26. The universal supply of electricity may be terminated based on the Customer's application in procedures defined by the REM Rules.
27. The Contract may also be terminated:
    1) Upon mutual consent of the Parties;
    2) Upon the unilateral initiative of the Customer, on condition that the Distributor has been duly notified and electricity supplied or, in the case of the Supplier's Customer, the distribution services provided have been completely paid for;
    3) Upon the unilateral initiative of the Distributor:
        a. In case of failure of the Customer to pay the advance amount within the period defined in Provision 3 of this Contract or if the Customer requested that the Distributor return the Advance Amount per Provision 11(1) of the Contract, as well as in other cases provided for in this Contract, laws, REM Rules, and EDN Code, on condition that the Customer has been notified in advance;
        b. If the Contract that was concluded for a certain period pursuant to the REM Rules is expired and the Customer has been duly notified 1 month prior to the expiration date;
        c. In the case where the entity with rights to the premises receiving electricity supply (building, construction site) has submitted a written request, if the Customer does not have a document verifying their eligibility for the premises (building, construction site) as prescribed by the REM Rules, on condition that the Customer has been informed in advance, except for the cases specified in the REM Rules;

d. Upon the death of the Residential Customer or upon the liquidation of the legal entity;

e. In case of obtaining Qualified Customer status pursuant to the REM Rules;

f. In other cases prescribed by the Law, REM Rules, Contract, and other legal acts of the Commission, on condition that the Customer has been notified in advance.

28. Amendments to this Contract upon agreement of the Parties shall be made in writing on condition that they do not contradict the currently effective model form of the Contract approved by the Commission and other normative documents of the Commission.
29. Amendments to or termination of this Contract shall not relieve the Parties from obligations undertaken and not fulfilled before the change of the Contract.

7. RESPONSIBILITIES OF PARTIES

30. Where one party fails to comply with or inadequately complies with undertaken obligations arising from this Contract, it shall bear responsibility under the Law, REM Rules, and EDN Code in cases and procedures defined in this Contract.
31. Where the periods defined in this Contract are violated, the Customer shall have the right to impose a penalty on the Distributor for each delinquent day in the amount of 0.1 percent of the Connection Charge, not exceeding the entire amount of the Connection Charge, and in cases defined in the EDN Code, in amounts and procedures specified by the EDN Code.
32. Where the period for payment of the difference between the Connection Charge and the Advance Amount defined in Provision 6 of the Contract is violated, the Distributor shall be eligible to impose a penalty on the Customer for each delinquent day equal to 0.1 percent of the difference, but not exceeding the entire amount of the difference.
33. Where the service quality requirements are violated, the Distributor shall be required to pay a penalty to the Customer in procedures established by the REM Rules and EDN Code.
34. For distribution of electricity with violations of quality indicators, the Distributor shall compensate the damages borne by the Customer in legally defined procedures.
35. Where the Customer (except for residential customers) violates the payment schedule defined in the Contract, the Distributor may impose a penalty on the Customer for each delinquent day equal to 0.1 percent of the amount due, not to exceed 10 percent of the entire debt. The penalty may be calculated from the 20th day of the month following the Settlement month, if the Distributor (according to procedures defined by the REM Rules) notified the Customer 7 days prior about the quantity and price of electricity supplied and, in the case of the Supplier's Customer, about the quantity and price of distribution services rendered. Otherwise, the penalty shall be calculated not later than 7 days after the notification according to procedures specified in the REM Rules.
36. Where the Customer consumes electricity by bypassing the commercial metering device, the quantity of electricity consumed shall be determined in procedures defined in the RoA Government decision.
37. The party to the Contract shall not bear responsibility for the violation of it, if the violation is caused by a force majeure situation. The cases deemed to be force majeure and the associated procedures shall be defined in the REM Rules.

8. OTHER REQUIREMENTS

38. The concepts used in this Contract shall have the definitions stated in the Energy Law, REM Rules, and EDN Code unless otherwise expressly defined in the Contract.
39. According to the Contract, the Customer shall agree to disclose the personal data they submitted in compliance with the REM Rules and EDN Code to make the information on electricity supplied (distributed) in accordance with the REM Rules available for other entities (including banks as well as payment and settlement organizations), and to enable the Distributor to fulfill its obligations under the Law and this Contract.

40. Disputes (disagreements) between the parties shall be settled through negotiations.
41. If a dispute (disagreement) is not settled by the parties, any party to a dispute (disagreement) may apply to the Commission requesting that it resolve the dispute within its jurisdiction, or may file a suit at a competent court if the parties fail to agree on resolving the issue through arbitration.
42. This Contract is signed on two legally equal copies, one for each party.

9. LIST OF ANNEXES THAT ARE AN INTEGRAL PART OF THE CONTRACT

43. The following annexes are made an integral part of the Contract:
    1) Annex 1: Calculation of the Consumption system connection charge;
    2) Annex 2: Technical Conditions for connection of the consumption system to the electric network (for a complex connection procedure defined in the EDN Code);
    3) Annex 3: Single line electricity supply diagram (for a complex connection procedure defined in the EDN Code);
    4) Annex 4: Data of Commercial (Control) metering devices of the Customer (sub-Customer);
    5) Annex 5: Direction, voltage, maximum permissible capacity of the Customer's (sub-Customer's) feeder;
    6) Annex 6: Boundary point between the electric network of the Distributor and the Consumption system of the Customer and on separation of responsibility for the operation of electric installations;
    7) Annex 7: Technological and/or emergency capacities;
    8) Annex 8: Additional conditions for Customers of 0.4 kV and higher voltage network (except for residential customers).

10. DETAILS OF PARTIES

Distributor

_____

Location

_____

Phone _____

Email _____

Taxpayer Number_____

Connection Charge Account

_____

Account for payment against electricity consumed

_____

Bank_____

License No.

_____

(Signature, Name, Surname)

SEAL
(if available)

Customer

_____

Location (Residential Address)

_____

Address for Notifications

_____

Email _____

Phone _____

Taxpayer Number (for legal entities)

_____

Bank _____

Account Number _____

_____

(Signature, Name, Surname)

ANNEX 1. CALCULATION OF THE CONSUMPTION SYSTEM CONNECTION CHARGE

1. The Connection Charge (CC) amount is _____, from which the Advance amount is _____.
2. The Connection Charge has been calculated according to the EDN Code as follows:
   CC = Cst + Cadd + Creserve
   Cst – description of the value, calculation (formula), respective components.
   Cadd – description of the value, respective components.
   Creserve – description of the value, respective components.

Distributor	**Customer**
_____	_____
(Name, Surname, Position)	(Name, Surname)
_____	_____
(Signature)	(Signature)

ANNEX 2. TECHNICAL CONDITIONS FOR CONNECTION OF THE CONSUMPTION SYSTEM TO THE ELECTRIC NETWORK

TECHNICAL CONDITIONS FOR TEMPORARY CONNECTION OF THE CONSUMPTION SYSTEM TO THE ELECTRIC NETWORK

Distributor	**Customer**
_____	_____
(Name, Surname, Position)	(Name, Surname)
_____	_____
(Signature)	(Signature)

ANNEX 3. SINGLE LINE ELECTRICITY SUPPLY DIAGRAM

Distributor

(Name, Surname, Position)

(Signature)

Customer

(Name, Surname)

(Signature)

ANNEX 4. DATA OF COMMERCIAL (CONTROL) METERING DEVICES OF THE CUSTOMER

Location of the metering device	Commercial (Control) Metering Device										Party responsible for integrity of commercial meters, metering transformers on the territory being the property of or controlled by the Customer
	Meter				Current Transformer			Voltage Transformer			
	Type, nameplate, type and number of the seal	Permissible current (A)	Nominal voltage (V)	Month and year of the next meter calibration	Type, nameplate, type and number of the Customer seal	Accuracy class	Transformation ratio	Type, nameplate, type and number of the seal	Accuracy class	Transformation ratio	
1	2	3	4	5	6	7	8	9	10	11	12

Distributor

(Name, Surname, Position)

(Signature)

Customer

(Name, Surname)

(Signature)

ANNEX 5. DIRECTION, VOLTAGE, MAXIMUM PERMISSIBLE CAPACITY OF THE CUSTOMER'S (SUBCUSTOMER'S) FEEDER

NN	Feeder direction name	Address	Electric load category (I, II, III)	Voltage at boundary point (kV)	Maximum permissible capacity (kW)	Number of working days and hours (hours)	Maximum demand load for working and non-working hours (kW)
1	2	3	4	5	6	7	8
1							
2							
3							

1. Column 6 of the above table shall be filled in according to the Technical Conditions provided to the Customer. Where Technical Conditions are not provided, Column 6 shall be filled in as follows:
   a. For Customers using a 0.22 kV voltage network, it is the product of the permissible current of the meter and nominal voltage;
   b. For Customers using a 0.4 kV network, it is the product of permissible current, nominal volume, and transformation ratio of the current transformer;
   c. For Customers using a 6(10) kV network, it is the product of permissible current, nominal volume, transformation ratio of the current transformer, and transformation ratio of the voltage transformer.
2. Column 4 of the above table shall be filled in according to the categories of electric loads defined in technical requirements for the equipment at electric installations established by the RoA Government Resolution No. 193-N of December 21, 2006.

Distributor

(Name, Surname, Position)

(Signature)

Customer

(Name, Surname)

(Signature)

ANNEX 6. BOUNDARY POINT BETWEEN THE ELECTRIC NETWORK OF THE DISTRIBUTOR AND CONSUMPTION SYSTEM OF THE CUSTOMER AND ON SEPARATION OF RESPONSIBILITY FOR ELECTRIC INSTALLATIONS OPERATION

1. The Boundary Point of the Parties is _____

2. The point of separation of the operational responsibility is_____

3. The Boundary Point between the electric installations of the Customer and Sub-Customer is _____
   _____

Distributor

(Name, Surname, Position)

(Signature)

Customer

(Name, Surname)

(Signature)

ANNEX 7. ACT ON TECHNOLOGICAL AND/OR EMERGENCY CAPACITIES

Maximum permissible capacity	Technological capacity	Emergency capacity	Duration of technological process (cycle)	Period required to provide emergency capacity
kW	kW	kW	hours	hours

No.	Feeding center	Feeding line	Feeding line load, kW	Emergency backup			Technological backup			Other capacities			Sub-customer
				Power receivers, power supply restriction of which can result in real and inevitable danger to human life and the environment	Feeding line emergency capacity, kW	Feeding line on which emergency capacity is transferred	Power receivers, power supply restriction of which can result in real and inevitable danger to human life and the environment	Feeding line technological capacity, kW	Feeding line on which emergency capacity is transferred	Capacity kW	Daily electricity consumption, kWh	Total load, kW	Technological and emergency backup capacity, kW
1	2	3	4	5	6	7	8	9	10	11	12	13	14
Total													

ANNEX 8. ADDITIONAL CONDITIONS FOR CUSTOMERS OF 0.4 KV AND OVER VOLTAGE NETWORK (EXCEPT FOR RESIDENTIAL)

1. In cases provided for by the RoA standard legal acts, the Parties shall be obliged to attach to this Contract the Act on fixing the technological and/or emergency capacities to be developed in accordance with the EDN Code.
2. Where the normal operation of commercial metering devices is technically impossible to ensure under the minimum load regimes, the quantity of electricity consumed shall be calculated based on the capacity of electric receivers that have been actually connected to the network during the entire period of minimum load and be added to the quantity calculated based on the commercial meter readings in procedures defined by the EDN Code.
3. Either the Distributor or the Customer may install devices to record and memorize electricity quality indicators at boundary points, in regard to which a bilateral act shall be developed and attached to this Contract.
4. If the electricity quality indicators defined by the RoA Legislation are breached, the reasons and the period when electricity was being supplied with violations of quality indicators shall be determined by the records of metering devices of the Distributor (Universal Supplier) or Customer, and if those are absent, by corresponding calculations using the records in operational documents of the Distributor (Universal Supplier) or Customer, in regard of which the Distributor (Universal Supplier) and Customer shall develop a bilateral act.
5. The Distributor (Universal Supplier) shall compensate the damages incurred by the Customer due to distribution of electricity with violation of quality indicators in procedures defined by the RoA Law.
6. In the event that the equipment, relay protection and automation devices of the Customer (except for residential) are transferred under the Distributor's operational supervision, the Parties shall be required to do so in procedures defined by the EDN Code.
7. The Customer shall be obliged:
   1) To ensure 24-hour free access for the operational staff of the Distributor authorized to carry out switching to the premises under its control to fulfill their obligations within the scope of their authorities;
   2) To immediately inform the Distributor about deficiencies and failures revealed on the equipment and relay protection and automation devices under its operational supervision, at the phone number: _____.
   3) To not exceed the maximum permissible capacity specified in Annex 5 to this Contract and to agree with the Distributor (Universal Supplier) on any change to the maximum permissible capacity.
8. The Distributor (Universal Supplier) shall not bear responsibility for the supply of electricity with violations of quality indicators for the period in which the Customer exceeds the defined maximum permissible capacity.

OTHER CONDITIONS (TO BE FILLED IN BY PARTIES)

9. _____

10. _____

ELECTRICITY DISTRIBUTION SERVICES AND ELECTRICITY UNIVERSAL SUPPLY CONTRACT (PUBLIC CONTRACT)

The Distributor (Universal Supplier) _____ (name)

represented by _____,
(name, surname, position, letter of authorization data)

and the Customer, collectively known as the Parties, hereby submit their Acceptance in accordance with the model form approved by the Public Services Regulatory Commission of the Republic of Armenia (RoA) (hereinafter, the Acceptance), being guided by the Energy Law and other laws of the RoA, Retail Electricity Market Trading Rules (hereinafter, REM Rules), Electricity Distribution Network Code (hereinafter, the EDN Code) approved by the RoA Public Services Regulatory Commission (hereinafter, the Commission) and other legal acts, have jointly concluded this contract (hereinafter, the Contract), which is public and is based on conditions presented below and data included in the Acceptance submitted by the Customer.

CHAPTER 1. SUBJECT OF THE CONTRACT

1. By this Contract, the Distributor shall provide to the Customer distribution service of electricity purchased from the Supplier or shall perform universal supply of electricity, and the Customer shall pay for the Distribution Service and the Universal Supply provided.

CHAPTER 2. RIGHTS AND OBLIGATIONS OF PARTIES

2. According to the Contract, the Parties shall have all those rights and obligations that are prescribed by the REM Rules and EDN Code.

CHAPTER 3. PRICE, QUANTITY, AND COST CALCULATION AND PAYMENT PROCEDURES FOR DISTRIBUTION SERVICE PROVIDED AND ELECTRICITY SUPPLIED

3. The quantity of electricity supplied in the Settlement month shall be determined according to the procedure defined in the REM Rules.
4. The price of electricity supplied to the Customer within the Settlement month, except for the cases specified in Provision 5 of this Contract, shall be calculated as a product of the tariff set forth by the Commission for the given voltage level and timeframe (if the Commercial metering device can perform differentiated metering) and the quantity of electricity supplied, whereas, in the case of the Supplier's Customer, the price of distribution service provided shall be calculated as a product of the distribution service tariff set by the Commission for the given voltage level and the quantity of electricity distributed.
5. In cases defined by the REM Rules, for the Universal Supplier to restart the Customer's supply of electricity, as well as in cases when the Customer did not obtain Qualified Customer status or did not select a Supplier in terms and procedures defined by the REM Rules and by the Wholesale Electricity Market Trading Rules approved by the Commission, the cost of electricity supplied by the Universal Supplier to the Customer within the Settlement month shall be calculated as a product of the tariff set forth by the Commission for the given Customer group and the quantity of electricity supplied.
6. Where the tariff is changed by the Commission, the new tariff shall become effective from the day it is defined by the Commission.

7. The Customer shall, according to the REM Rules, pay the cost of electricity supplied or, in the case of the Supplier's Customer, the cost of distribution services provided during the previous month to the bank account of the Distributor mentioned in the Contract prerequisites once the billing document is submitted by the Distributor (personally or by authorized representative) in terms and procedures defined in the REM Rules.
8. In case of calculation of penalties in compliance with the REM Rules, the Distributor shall first redeem the cost of electricity supplied or, in the case of the Supplier's Customer, the cost of distribution service rendered starting from the previously incurred indebtedness and only then shall cover financial liabilities under the calculated penalties.
9. If there are outstanding financial liabilities, the Distributor shall not suspend the Customer's electricity supply on condition that the latter presents payment guarantees acceptable for the Distributor or develops with the Distributor a debt repayment schedule. This Provision shall not restrict the Distributor's right to suspend the Customer's supply in case of violation of the repayment schedule, ensuring compliance with the procedures on suspension of electricity supply of the given Customer as prescribed in the REM Rules and EDN Code.
10. If there are no outstanding liabilities to the Distributor (Universal Supplier), payments of the Customer shall be used as deposit amounts to cover future liabilities, unless the Customer has requested that the Distributor refund these deposit amounts.

CHAPTER 4. VALIDITY OF CONTRACT

11. The Contract shall come into force from the moment the Acceptance is approved by the Distributor.
12. In cases when the Commission approves a new model form or introduces amendments or supplements thereto, the signed contracts shall be deemed new or shall be deemed signed and modified in compliance with the introduced changes starting on the date of effectiveness of the corresponding legal act.
13. The Contract is concluded for an indefinite period, except for the cases defined in REM Rules. Where the given case requires concluding a temporary contract according to REM Rules, 1 month prior to the expiration of the temporary contract's validity period, each party to the contract may notify the other party of the termination of the contract. If, after the expiration of the validity period, the Distributor has not sent a notification and the Customer continues consuming electricity, the Contract validity shall be considered extended under the same conditions and for the same period, except for the cases defined in the REM Rules.
14. The universal supply of electricity may be terminated based on the Customer's application under procedures defined by the REM Rules.
15. The Contract shall be terminated:
    1) Upon mutual consent of the Parties;
    2) Unilaterally by the Customer on condition that the latter duly informed the Distributor of the termination and completely paid for electricity supplied, and in case of the Supplier's Customer, for the distribution services rendered;
    3) Upon the unilateral initiative of the Distributor;
        a. If the Contract that was concluded for a certain period pursuant to the REM Rules is expired and the Customer has been duly notified 1 month prior to the expiration date;
        b. If the entity with the rights to the premises receiving electricity supply (building, construction site) has submitted a written request and if the Customer does not have a document verifying their eligibility for the premises (building, construction site) as prescribed by the REM Rules, on condition that the Customer has been informed in advance, except for the cases specified in the REM Rules,
        c. Upon the death of the Residential Customer or upon the liquidation of the legal entity,

d. In case of obtaining Qualified Customer status pursuant to the REM Rules,
e. In other cases prescribed by the Law, REM Rules, Contract, and other legal acts of the Commission, on condition that the Customer has been notified in advance,

16. Amendments to this Contract upon mutual agreement of the Parties shall be made in writing on condition that they do not contradict the model form approved by the Commission and currently effective and other legal acts of the Commission.
17. Amendments to or termination of the Contract shall not relieve the Parties from obligations undertaken and not fulfilled prior to the change of the Contract.

CHAPTER 5. RESPONSIBILITIES OF PARTIES

18. If the parties fail to comply with or inadequately comply with undertaken obligations arising from the Contract, they shall bear responsibility in procedures and cases defined by the Law, REM Rules, EDN Code, and the Contract.
19. If the Distributor violates distribution service quality requirements, it shall be required to pay a penalty to the Customer in procedures established by the REM Rules and EDN Code.
20. For the provision of distribution services with violations of quality indicators, the Distributor shall compensate the damages borne by the Customer in legally defined procedures.
21. If the Customer (except for residential customers) violates the payment schedule defined in the Contract, the Distributor may impose a penalty on the Customer for each delinquent day equal to 0.1 percent of the amount due, not to exceed 10 percent of the entire debt. The penalty may be calculated from the 20th day of the month following the Settlement month if the Distributor has notified the Customer 7 days prior in procedures defined by the REM Rules about the quantity and price of electricity supplied and, in the case of the Supplier's Customer, about the quantity and price of distribution serves rendered. Otherwise, the penalty shall be calculated not later than 7 days after the notification in procedures specified in the REM Rules.
22. Where the Customer consumes electricity by bypassing the commercial metering device, the quantity of electricity consumed shall be determined in procedures defined in the RoA Government decision.
23. The party to the Contract shall not bear responsibility for the violation of the Contract, if the violation is caused by a force majeure situation. The cases considered force majeure, as well as procedures thereon, shall be defined by the REM Rules.

CHAPTER 6. OTHER REQUIREMENTS

24. The concepts used in the Contract shall have the definitions stated in the Energy Law, REM Rules, and EDN Code, unless otherwise defined in the Contract.
25. According to the Contract, the Customer shall agree to disclose the personal data submitted by them in compliance with the REM Rules and EDN Code, to make the information on electricity supplied (distributed) in accordance with the REM Rules available for other entities (including banks as well as payment and settlement organizations), and to enable the Distributor to fulfill its obligations under the Law and this Contract.
26. Disputes (disagreements) between the parties shall be settled through negotiations.
27. If a dispute (disagreement) is not settled by the parties, any party to a dispute (disagreement) may apply to the Commission requesting that it resolve the dispute within its jurisdiction, or may file a suit at a competent court if the parties fail to agree on resolving the issue through arbitration.

CHAPTER 7. DISTRIBUTOR DETAILS

Title

Location

Phone _____

Email _____

Taxpayer Number

_____

Account number _____

Bank_____

License No.

ACCEPTANCE OF THE ELECTRICITY DISTRIBUTION SERVICES AND ELECTRICITY UNIVERSAL SUPPLY CONTRACT (PUBLIC CONTRACT)

1. By this Acceptance, the Customer _____

_____

(Customer name, title)

shall completely and unconditionally accept all terms and conditions defined by the model form of the Public Contract on provision of electricity distribution services and electricity universal supply by declaring its willingness to sign a Contract with the Distributor for

☐ household
☐ non-household
type of consumption at the premises where the consumption system is installed:

_____

(Consumption system location)

2. Other details of the Customer:

Details and the copy of the document verifying identity (State registration number): _____

Social security number (Tax identification number): _____

Residence address _____

Details for notification

Postal address: _____

Email address: _____

Phone: _____

Bank details

Bank: _____

Account number: _____

Usable capacity_____

Voltage of the electricity supply network_____ Phase _____Volt

3. A document verifying (certifying) the rights or acquisition of rights towards the premises where the consumption system is located (building, construction site), or, in the case of a legal entity, a document verifying (certifying) the rights to the premises where the consumption system is located (building, construction site). _____

_____

_____

4. Other details _____

Customer /Signature/

CONNECTION OF CONSUMPTION SYSTEMS OF MULTI-APARTMENT BUILDINGS UNDER CONSTRUCTION OR NEWLY DEVELOPING AREAS TO ELECTRIC NETWORK CONTRACT

_____ _____20__

(Location)

Distributor _____

(name, location)

represented by _____,

(name, surname, position, letter of authorization data)

acting on the basis of _____ as the First Party,

(document regulating the activity)

and the entity that applied for connection of consumption systems of a multiapartment building under construction or newly developing area to the electric network (hereinafter, Developer)

_____,

(name, surname, passport or ID number, in case of a legal entity - company or organization name, name and surname and position of the representative; in case of an authorized person – the letter of authorization)

as the Second Party, collectively known as the Parties, being guided by the Energy Law and other laws, Electricity Retail Market Trading Rules (hereinafter, Trading Rules), Electricity Distribution Network Code (hereinafter, the Network Code) approved by the RoA Public Services Regulatory Commission (hereinafter, the Commission), this Contract, and other legal acts, have concluded this Contract.

CHAPTER 1. SUBJECT OF THE CONTRACT

1. Under this Contract, the Distributor shall undertake to connect the consumption system for _____ (domestic for residential customers, non-domestic for other customers) purposes located at _____ _____(hereinafter, the Consumption System) to the electric networks and the Developer shall undertake to pay for the Connection.

CHAPTER 2. ELECTRIC NETWORK CONNECTION PROCEDURE

2. The Connection Charge for connecting the Customer's Consumption System (hereinafter, Connection Charge) shall amount to _____AMD including VAT, as outlined in Annex 1 to this Contract.
3. Within 24 months starting from the conclusion of this Contract, the Developer shall transfer the Connection Charge to the Distributor's bank account specified in the Details of the Parties.
4. The Distributor shall ensure implementation of the connection to the electric network within __days following the payment of the Connection Charge, not exceeding the dates defined in the Network Code, to be carried out based on Technical Conditions specified in Annex 2 of this Contract and/or according to a single line electricity supply diagram defined in Annex 3 of this Contract.
5. Where the Developer failed to fulfill its payment obligation per Provision 3, the Contract shall be terminated according to Provision 16(3) of this Contract.

CHAPTER 3. BASIC RIGHTS AND OBLIGATIONS OF PARTIES

6. Distributor's obligations:
   1) To ensure connection of the consumption system to the electric network according to Provision 4 without energizing the connection;
   2) If the Developer did not accomplish necessary works according to Provision 9(2) of the Contract, to connect the consumption system to the electric network within 3 business days after having been informed about the accomplishment of the required works;
   3) Before the 10th day of the month following the connection, to provide to the Developer the Connection Charge calculations;
   4) In cases and procedures provided for by Provision 9(1) of this Contract and the Network Code, to return the Connection Charge to the Developer in the form preferred by the latter (cash or non-cash);
   5) In cases provided for in Provision 12 of this Contract, to duly inform the Developer about the changes in the connection dates not later than in 3 business days;
   6) To pay a penalty to the Developer for violation of dates defined in this Contract pursuant to Provision 11 of this Contract.
7. Distributor's rights:
   1) Where the Developer violates its obligation per Provision 3 of this Contract, to terminate the Contract based on Provision 16(3).
8. Developer's obligations:
   1) To pay the Connection Charge according to Provision 3 of the Contract;
   2) To implement necessary works for connection of the consumption system to the electric network and, in case of violation of that obligation, to inform the Distributor about the date the works are accomplished.
9. Developer's rights:
   1) To request the Distributor in written form that to return the Connection Charge within 5 business days after the payment is made. Once the period is expired, the Connection Charge shall be subject to return only on the condition that the Distributor's actual expenses for activities on connection of the consumption system to the electric network are compensated within 5 business days after the claim is made.
   2) Where the dates specified in this Contract are violated, to impose a penalty on the Distributor in procedures defined by Provision 11 of the Contract.

CHAPTER 4. RESPONSIBILITIES OF PARTIES

10. Where a Party fails to comply with or inadequately complies with undertaken obligations arising from this Contract, it shall bear responsibility in procedures defined by RoA Legislation, Trading Rules, the Network Code, and this Contract.
11. Where the periods defined in this Contract are violated, the Developer shall have the right to impose a penalty on the Distributor for each delinquent day in the amount of 0.1 percent of the electric network Connection Charge, not exceeding the entire amount of the Connection Charge; in cases defined by the EDN Code, it shall be paid in the amount and procedures set forth in the EDN Code.
12. A party to the Contract shall not bear responsibility for violation of contractual obligations if it is caused by consequences of force majeure situations. Cases deemed to be force majeure situations, as well as their application procedures, shall be defined in the EDN Code.

CHAPTER 5. DISPUTE RESOLUTION

13. All disputes and disagreements arising from this Contract shall be resolved through negotiations, and in case of a written application by one of the Parties, through the Commission's mediation.
14. Provision 13 of the Contract shall not restrict the right of the Parties to resolve the dispute in court unless the parties agreed to pass the issue to arbitration.

CHAPTER 6. ENTRY INTO FORCE, MODIFICATION AND TERMINATION PROCEDURE, VALIDITY OF CONTRACT

15. This Contract shall come into force at the moment of signing and shall be valid until all obligations of Parties associated with the connection of the consumption system to the electric network stated in Chapter 3 of the Contract are completely fulfilled.
16. The Contract shall be terminated:
    1) Upon mutual consent of the Parties;
    2) Upon the unilateral initiative of the Developer, on condition that the Distributor has been duly notified;
    3) Upon the unilateral initiative of the Distributor in case of failure of the Developer to pay the Connection Charge according to Provision 3 of this Contract or if the Customer requested the Distributor to return the Connection Charge according to Provision 9(1) of the Contract, as well as in cases specified by the Laws, Trading Rules, Network Code, and this Contract, on condition that the Developer has been notified in advance.
17. In cases when the Commission approves a new model form or introduces amendments or supplements thereto, the signed contracts shall be deemed new or shall be deemed signed and modified in compliance with the introduced changes starting on the date of effectiveness of the corresponding legal act.
18. Amendments to this Contract shall be made in writing upon mutual agreement of the Parties, on condition that they do not contradict the existing model form approved by the Commission, Trading Rules, Network Code, legal acts approved by the Commission, and other normative documents.
19. Amendments to or termination of this Contract shall not relieve the Parties from obligations that were undertaken and not fulfilled before the change of the Contract.
20. This Contract shall be signed in two legally valid and equal copies, one for each Party.

CHAPTER 7. AVAILABILITY AND CONFIDENTIALITY OF INFORMATION

21. Any and all data subject to exchange between the parties shall be submitted (published) in procedures defined in the Trading Rules and Network Code.
22. In the case of failure to submit, delay in submission, or submission of false or deficient information, any party shall bear responsibility for damages caused thereby.
23. Information that the parties became aware of shall be used by them exclusively for the purposes of this Contract.
24. Sharing of information between the parties to this Contract shall be in the public domain unless it is considered and marked as "Confidential" by the Law or by the entity that submitted the information. While receiving and then using confidential information, the relevant entity shall ensure confidentiality and be responsible for illegal publication thereof.
25. In cases and procedures defined in the Law, the Retail Market Participants and the Distributor shall be eligible to disclose confidential information.

CHAPTER 8. LIST OF ANNEXES THAT ARE AN INTEGRAL PART OF THE CONTRACT

26. The following annexes form an integral part of the Contract:

1) Annex 1 on Consumption System Connection Charge;

2) Annex 2 on Technical Conditions for Connection of the Consumption System to the Electric Network;

3) Annex 3 on Single Line Electricity Supply Diagram of the Developer.

CHAPTER 9. DETAILS OF PARTIES

Distributor

_____

Location

Phone _____

Email _____

Taxpayer

Number _____

Connection Charge Account

_____

Account for Payment against electricity consumed

_____

Bank _____

License No.

_____

(Signature, Name, Surname)

SEAL
(if available)

Developer

_____

Location (Residential Address)

Address for Notifications

_____

Email _

Phone _____

Taxpayer Number (for legal entities)

_____

Bank _____

Account Number

_____

(Signature, Name, Surname)

ANNEX 1. CONSUMPTION SYSTEM CONNECTION CHARGE

1. The Connection Charge (CC) amount is _____.

2. The Connection Charge has been calculated according to the Network Codes _____(exact reference).

CC = Cst + Cadd + Creserve

Cst – description of the value, calculation (formula), respective components.

Cadd – description of the value, respective components.

Creserve – description of the value, respective components.

Distributor	**Customer**
_____	_____
(Name, Surname, Position)	(Name, Surname)
_____	_____
(Signature)	(Signature)

ELECTRICITY MARKET TRANSMISSION NETWORK CODE OF THE REPUBLIC OF ARMENIA

SECTION 1. GENERAL PROVISIONS

CHAPTER 1. SUBJECT AND DEFINITIONS

1. The Republic of Armenia (RoA) Electricity Market Transmission Network Code (hereinafter, the ETN Code) shall regulate planning of the electricity system's development process, electricity system short-term planning, electricity system operational management and dispatch, and connection of new capacities to the grid, as well as define the requirements set for electricity Metering Complexes in the electricity system and procedures focused on the improvement of efficiency of electricity system operations.
2. The main definitions used in the ETN Code:

1)	**Transient state**	The regime of Electricity system operation characterized by a significant change in parameters that takes the system from one state to another one.
2)	**Primary Reserve**	Active capacity of the generating unit operating synchronously with the electricity system that can be automatically loaded or shed accordingly in case of deviation from the defined frequency value.
3)	**Commercial Metering**	Metering of electricity (capacity) quantities and provided services subject to payment within the framework of trading relations of the Wholesale Electricity Market (hereinafter, WEM) Participants.
4)	**Asynchronous state**	Transient state of the Electricity system that results in disturbance of the synchronous operation of the parts of the system.
5)	**Automated Load Shedding Program**	Automated load shedding program of the electricity system implemented by the ESO in Emergency Situations through the action of the system automated devices.
6)	**Generator**	An entity holding a license for electric energy (capacity) generation.
7)	**Export Point**	Crossing point of the interconnection line and the state border, where the export of electricity is carried out.
8)	**Distribution Network**	A unified system of electricity distribution lines, substations, and other facilities controlled and operated by the Distributor.
9)	**Distributor**	An entity holding a license for electricity (capacity) distribution.
10)	**Normal State**	Operational parameters of the electricity system in real time, when they are within the ranges of the reliability and security indicators stated in Annex 1 of the ETN Code (hereinafter: RS Indicators) defined for the normal state.
11)	**Normal scheme**	Operative disposition of the Electricity system that ensures the maintenance of the Normal State.
12)	**Transaction**	An agreement between the WEM Trade Participants in respect of electricity trading in all segments and components of the WEM or a direct contract signed with a foreign natural person or legal entity on the export of electricity or on the import of electricity to be sold in the WEM or to satisfy its own demand.

13)	**Universal Supplier**	An entity holding a universal supplier license.
14)	**Secondary Reserve**	The part of the active capacity regulation range (increased or reduced) of the generator operating synchronously with the electricity system that is used for frequency control, compensation of capacity imbalance, elimination of overloading of transit connections, and restoration of the Primary Reserve during the primary regulation.
15)	**Tertiary Reserve**	The reserve capacity of the generator in the electricity system in the cold reserve, used to replace Primary and Secondary reserves.
16)	**Ten-Year Network Development Plan (TYNDP)**	The development plan of the Transmission Network described in Section 2 of the ETN Code.
17)	**EDN Code**	The Republic of Armenia Electricity Market Distribution Network Code approved by the Commission.
18)	**Security of the Electricity System**	The property of the electricity system to ensure operational parameters that are safe for any of its components that are part of the system or facilities connected to the system.
19)	**Dynamic (transient) Stability of the Electricity System**	The ability of the electricity system to move to the Sustainable or Normal state after a significant change to the state.
20)	**Reliability of the Electricity System**	The property of the electricity system to ensure generation, transmission, distribution, and supply of the electricity to customers within the specified range of technical parameters.
21)	**Static Stability of the Electricity System**	The ability of the electricity system to move to the Sustainable or Normal state after minor disturbances.
22)	**Annual Adequacy Forecast (AAF)**	A complex of annual forecasted indicators of electricity consumption, losses and own needs, generation, import, and export defined in the WEM Rules.
23)	**Electricity System**	The complex of installations for electricity generation, transmission, distribution, and consumption, as well as equipment and devices for their management, relay protection, system automation, and communication that are under operational management and/or control (hereinafter, referred to as operational subordination) of the ESO.
24)	**Data Acquisition System (DAS) Chief Administrator**	An authorized person appointed by the EMO responsible for the management of the Automated Data Acquisition System in the Wholesale Electricity Market.
25)	**DAS Administrator**	An authorized person appointed by the Utility-Scale Plant, Transmitter, Distributor and Qualified Customer through whom the DAS Chief Administrator manages the DAS.
26)	**WEM Rules**	The Wholesale Electricity Market Trading Rules of the RoA.
27)	**WEM Participants**	Generator, Universal Supplier, Supplier, Trader, Qualified Customer, Transmitter, Distributor, ESO, and EMO.
28)	**WEM Contract**	A contract between WEM Participants for participation in the WEM.
29)	**Emergency State**	Real-time operational parameters of the Electricity system when they are within the range of RS Indicators defined for the Emergency state.

30)	**Dispatch**	Universal group of processes and activities required for electricity system technological management with a purpose of ensuring opportunities for electricity generation, import, export, and transit, as well as for forecasted consumption volumes declaration and planning, and for covering the entire electricity demand in real time to ensure supply of electricity of the required quality in compliance with the RS Indicators.
31)	**Transmission Network**	The unified system of electricity transmission lines (including substations and other facilities), under the management and operation of the Transmitter, through which electricity is transmitted to the distribution network and customers, exported (imported), and/or transited to a third country.
32)	**Transmitter**	An entity holding an electricity (capacity) transmission license.
33)	**Utility-Scale Customer**	A Qualified Customer with installed capacity of 10 MW and above, connected to the transmission or distribution network.
34)	**Utility-Scale Plant**	A power plant with installed capacity of 10 MW and above, connected to the transmission or distribution network.
35)	**System Services**	Services provided by WEM Participants in cases and procedures defined by the ETN Code for the reliable and safe operation of the electricity system,
36)	**Dispatcher of the ESO**	An authorized entity that performs dispatching services on behalf of the ESO.
37)	**Electricity System Operator (ESO)**	An entity holding the license for provision of Electricity System Operator services.
38)	**Commission**	The Public Services Regulatory Commission of the RoA.
39)	**Metering Point**	Commercial and control metering points specified in the WEM Contract.
40)	**Metering Complex**	A set of combined devices envisaged for measurement and settlement of electricity (capacity), including current and potential transformers, electricity meters, impulse sensors, modems, adders, connection wires, and uninterruptible electricity feeding devices ensuring autonomous reliable feeding for at least 1.5 hours, which are connected to each other according to the scheme approved by design.
41)	**Settlement Period**	A settlement period of 60 minutes' duration.
42)	**Balancing Service Provider Generator (BSP)**	A Generator providing Balancing services under an electricity generation license and a wholesale trading license, as defined in the WEM Rules.
43)	**Balancing**	A set of processes and activities required for technological management of the electricity system implemented by the ESO to cover the entire electricity demand in real time, which will ensure electricity supply of defined quality maintaining RS Indicators.
44)	**Connection Point**	A physical point of the Transmission Network, to which the generation facility and/or the consumption system of the Applicant are connected.
45)	**Connection Contract**	An agreement signed between the Transmitter and the Applicant on connection of the generating facility and/or the consumption system of the Applicant to the Transmission Network.

46)	**Connection Reference or Reference**	A document on the possibility of connecting to the Transmission Network provided to the person intending to obtain a license for electricity generation.
47)	**Connection Capacity**	Capacity of a new or reconstructed facility and equipment being connected to the Transmission Network.
48)	**Import Point**	A crossing point on the interconnection line, through which import of electricity is implemented.
49)	**Normative contingency**	Failures in the Electricity system that are mandatory to study for assessment of reliability and security.
50)	**Electricity Market Operator (EMO)**	An entity holding the license for provision of electricity market operator services.
51)	**Qualified Customer**	A Customer who is eligible to purchase electricity or to import it for their own needs and meets the requirements set forth in the WEM Rules.
52)	**Contingency**	Failure of the normal state of Electricity system operation.
53)	**Parameters of the States**	The values for capacity, voltage, current, and frequency of the Electricity system.
54)	**Boundary Point**	The border of balance ownership of electricity facilities.
55)	**Technical Conditions**	Technical requirements for connection to the Transmission Network at least cost, to ensure connection of facilities at technical parameters defined in the application for connection and metering of electricity.
56)	**Available capacity**	Maximum capacity subject to Dispatch by the ESO, which is determined by reducing the capacity defined in accordance with Annex 2 of the WEM Rules by the capacity of limitations resulting from climatic conditions at thermal and nuclear power plants (external air temperature, humidity, location altitude), water flow and pressure at hydropower plants, as well as the deterioration of main equipment, thermal load, and residual physical resources.

CHAPTER 2. OBJECTIVES OF THE ETN CODE

3. The objectives of the ETN Code are:
   1) To regulate development planning and the normal operation of the electricity system;
   2) To regulate within the electricity system the activities of the ESO, Generators (including Utility-Scale Plants), the Transmitter, the Universal Supplier, Suppliers, the Distributor, the EMO, Qualified Customers, and Applicants as well as to define the rights and obligations of all those mentioned, enabling the ESO to ensure secure and reliable, effective and transparent operation of the grid, thus reducing security threats to the electricity system;
   3) To provide open, transparent, and non-discriminatory access and use of the transmission system;
   4) To establish an effective system for settlement of disputes among WEM Participants and Applicants.

CHAPTER 3. INFORMATION SUBMISSION AND NOTIFICATION

4. The exchange of information among the WEM Participants, as well as the submission of documents, shall be performed in a proper way as defined in Provision 5 of the ETN Code.
5. Within the framework of the ETN Code, the exchange of information among the WEM Participants

as well as the submission of documents shall be deemed appropriately performed if the information has been sent by registered letter with a notice of delivery or by other means securing the integrity of the message (including sending a message to a phone number specified by the WEM Participant or Applicant), or by electronic communication systems (including to the email specified by the WEM Participant or Applicant), as well as through other electronic communication means defined by legislation, or if it has been delivered with a mail delivery confirmation, unless otherwise specifically mentioned in the ETN Code. In case of notification through the Market Management System (MMS), the information presented to the EMO shall be deemed notified by the given participant to other WEM Participants whom it may concern.

6. The WEM Participant shall be liable for the accuracy of information provided in the WEM.
7. Where inaccuracies are revealed in the information provided by a WEM Participant, the person who revealed those inaccuracies shall, within no more than 3 business days after the inaccuracies have been revealed, submit the information to an authorized person and the latter shall make appropriate corrections within 1 business day after being notified.
8. In cases provided for by the ETN Code, the EMO and ESO shall ensure the complete publication of information presented by WEM Participants.
9. A WEM Participant shall respond to the inquiries, applications, complaints, or suggestions of other WEM Participants within 5 business days upon receiving them, unless another term is defined by the ETN Code for the specific cases.
10. Information shared by WEM Participants with each other shall be in the public domain if it is not deemed confidential in accordance with the Law or if the WEM Participant who presented that information does not consider it confidential and did not mark it as "Confidential information" according to the RoA legislative requirements.
11. A WEM Participant shall be eligible to disclose confidential information only in cases and procedures defined by the law and shall bear responsibility for violating legislative requirements regarding the information's confidentiality.
12. Any data, record, or document provided in the context of the ETN Code shall be preserved for at least 5 years, but not less than a period defined in the legislation for storage of such type of documentation.

CHAPTER 4. WEM PARTICIPANTS' RESPONSIBILITIES, DISPUTE (DISAGREEMENT) RESOLUTION

13. A WEM Participant shall bear responsibility for non-fulfillment or inadequate fulfillment of the provisions of the ETN Code by the Law on Energy (hereinafter, the Law) and in the procedures defined by the WEM Contract.
14. A WEM Participant shall not be responsible for violations defined in the ETN Code if they happened due to force majeure circumstances.
15. In terms of the ETN Code, any circumstance or event (or after-effect of that event) is considered a force majeure situation if it led (or may lead or will lead) to non-fulfillment or inadequate fulfillment of obligations defined by the ETN Code and at the same time is characterized by the features stated below:
    1) Is out of control of the WEM Participant;
    2) The WEM Participant undertook all possible actions and efforts (including precautional, alternative, legally defined) to prevent, weaken, eliminate, or avoid the influence of those circumstances (after-effects);
    3) The WEM Participant notified the other party about such circumstances in the shortest possible time but not later than within 10 days after being informed of the circumstance.
16. In terms of the ETN Code, force majeure includes but is not limited to the following situations:
    1) Natural and man-made calamities; epidemics; acts of God (including floods, earthquakes, hurricanes,

tornados, thunderstorms, heavy rains with lightning, snowstorms and landslides); nuclear, chemical, or biological contamination; strikes; and public disorders;

2) Rebellions, terroristic acts, wars, invasions, armed conflict, actions of foreign enemies, and blockades that take place on or involve the territory of the RoA and could not be reasonably predicted;

3) An act, activity, or inactivity of a state and municipal agency or other authorized body, due to which no permission or right was issued or extended to facilitate fulfillment of obligations, or due to which fulfillment of obligations was hindered, on condition that the WEM Participant acted in compliance with the RoA legislation.

17. Where a dispute (disagreement) arises between the WEM Participants, the parties shall resolve it through negotiations.
18. The EMO and the ESO shall facilitate alternative dispute resolution within the framework of their jurisdictions.
19. If a dispute (disagreement) is not settled by the parties, any party may apply to the Commission requesting that it resolve the dispute within its jurisdiction, as well as may file a suit at a competent court unless the parties have agreed to submit their dispute to arbitration.

SECTION 2. LONG-TERM PLANNING

CHAPTER 5. GENERAL PROVISIONS

20. The purpose of long-term planning is to develop an economically justified least cost TYNDP, which will ensure the continued reliable and secure operation of the electricity system.
21. Long-term planning is implemented based on requirements of the Law, this section, and the technical regulations, as well as the RS Indicators.
22. The implementation of the following measures and functions in the electricity system shall be reasonably justified in the course of the long-term development planning:
    1) Construction of new and decommissioning of the existing facilities;
    2) Reconstruction or upgrading of the existing facilities;
    3) Modernization of relay protection and automation devices;
    4) Replenishment and modernization of system automation devices;
    5) Re-configuration of the Transmission Network topology;
    6) Introduction of new technologies.
23. The long-term planning process shall comprise the following stages:
    1) Data collection and processing;
    2) Studies required for long-term planning;
    3) Modeling;
    4) Development and approval of the TYNDP.
24. The ESO and the following WEM Participants shall participate in the process of long-term planning (hereinafter, ELTP Participants):
    1) Utility-Scale Plants;
    2) Transmitter;
    3) Distributor;
    4) Utility-Scale Customers.
25. The TYNDP shall be prepared by the ESO once per 2 years, considering therein the development of the Electricity system within the next 10-year period.
26. To develop the TYNDP, the ESO may engage independent experts or organizations.
27. All actions and projects proposed in the TYNDP shall include assessment of the time schedule for the construction and rehabilitation works, which will incorporate the time schedules for obtaining permissions from the state, municipal self-government, and regulatory bodies for the planning and design of such projects and for starting construction works.

CHAPTER 6. LONG-TERM PLANNING STANDARDS AND CRITERIA

28. The long-term planning process shall consider changes in the electricity consumption and generation levels and structure, new technologies, changes to prices of energy carriers, and any other possible scenarios and situations.
29. The long-term planning process shall incorporate assessments of electricity system operation regimes by seasons (winter, spring, summer, autumn).
30. The long-term planning process shall evaluate possible risks of violation of the normal operation of the system and develop measures aimed at minimizing their negative consequences.
31. While developing the TYNDP, the ESO shall ensure that RS Indicators of the electricity system are adequately maintained in the event that any single element of a multi-element group is lost.
32. Various preparatory arrangements to ensure operational security shall be addressed in the long-term planning process in case of Contingencies deemed to be exceptional from the viewpoint of RS Indicators of the electricity system. The choice of preparatory measures shall depend on the comparative analysis of the technical and economic factors and shall be separately explained in the TYNDP, taking into account the following:

1) The probability of occurrence of that type of Contingency;
2) The possible consequences of that type of Contingency;
3) The expenses incurred in order to exclude the emergence of such Contingencies;
4) The cost of introducing protective measures required to prevent the extension of the Contingency.

33. The long-term planning shall be carried out in such a way:
    1) To maintain all parameters defined by the RS Indicators for the Normal State for forecasted regimes of generation and consumption in Electricity System;
    2) To maintain the parameters of the Normal State defined by the RS Indicators in cases of a design basis contingency at any of the electricity system elements (generator, line, transformer, etc.);
    3) To be capable of restoring the Normal State of operation after any type of contingency, in parameters and time limits defined by RS Indicators parameters.
34. The following shall be considered during the long-term planning process:
    1) Electricity generation, transmission, distribution, and interconnection load flow with neighboring countries;
    2) Information about the connection of new as well as reconstructed facilities to the Transmission Network;
    3) The State policies in regard to the energy sector, including but not limited to effective use of water resources, promotion of renewable energy sources development, mitigation of environmental effects, etc.

CHAPTER 7. DATA COLLECTION AND PROCESSING

35. The ESO shall collect, process, and summarize the data and information required for long-term planning.
36. For long-term planning purposes, the ESO shall develop the forms of information subject to submission by the relevant ELTP Participants.
37. To receive data and information for long-term planning purposes, the ESO shall apply to the ELTP Participants and, within 20 business days of receiving the application, they shall provide the necessary information to the ESO.
38. In cases when an ELTP Participant intends to take their facilities that are a part of the electricity system out of operation, they shall notify the ESO at least 2 years prior to such action.
39. The ESO may request that the ELTP Participants provide additional information in order to check the accuracy of the planning data. The additional information requested shall be submitted to the ESO within 10 business days upon the receipt of the request.
40. When an ELTP Participant identifies an inaccuracy in the information provided for the TYNDP, it shall notify the ESO in writing within 3 business days after revealing inaccuracies.

CHAPTER 8. STUDIES AND MODELING REQUIRED FOR LONG-TERM PLANNING

41. The electricity system's long-term planning within the framework of the TYNDP shall be implemented based on the following studies:
    1) Assessment of the dynamics of the internal demand, import, and export;
    2) Assessment of the operation states and losses of the Transmission Network;
    3) In case of connection of new or reconstructed facilities to the grid, assessment of the impact of such connection on the grid;
    4) Assessment of the timetable for commissioning of new facilities and remedial measures for elimination of deficiencies at the existing facilities;
    5) Assessment of impact due to expected changes in the electricity and capacity demand;

6) Study ensuring load flows, short circuits, static and dynamic stability, and voltage levels at checkpoints;
7) Assessment of system performance during Normal and Emergency states pertinent to the electricity system;
8) Assessment of electricity system behavior during disturbances (deviations) and switching;
9) Study of potential congestions at network elements;
10) Assessment of capacity reserves (active and reactive) under synchronous and island operation regimes;
11) Any other assessment or study to ensure the reliable and secure operation of the electricity system in the future at economically justified least cost.

42. All studies required for the long-term planning of the electricity system within the framework of the TYNDP are performed through modeling. Modeling shows the impact of real objects, processes, and events on the electricity system's forecasted indicators. The electricity system development models are developed to evaluate the potential to cover the anticipated consumption demand in all sectors of the economy from domestic sources as well as electricity export and import opportunities.
43. The following fundamental assumptions shall be accepted for the purposes of modeling the electricity system in the context of the TYNDP:
    1) Capacity demands are represented at peak, off-peak, and base load conditions for each third Wednesday and one non-business day of each month;
    2) Energy and capacity demand are modeled for forecasted internal consumption, export, and import, as well as transit modes;
    3) Analysis is conducted to assess the impact that deviations from the forecasted demand may have on the electricity system modes;
    4) Electricity system Dispatch shall be performed on an annual basis so that the electricity supply to customers can be ensured at least cost, considering the purchase guarantees to the Generators;
    5) Scheduled maintenance outages of facilities and other limitations necessary for mode adjustments are taken into account;
    6) Transmission facilities are modeled to consider the scheduled maintenance and construction outages and long-term forced outages;
    7) Interconnected exchanges are modeled to study their impact on electricity system performance;
    8) Relay protection and system automation parameters are modeled for the purposes of adjustments needed.
44. Modeling shall be performed for the main and alternative development scenarios of the electricity system—optimistic and pessimistic scenarios.
45. The electricity system characteristics to be modeled must comply with the established RS Indicators.
46. The modeling software used during electricity system long-term planning shall ensure the equivalent reproduction of actual processes.

CHAPTER 9. DEVELOPMENT AND APPROVAL OF THE TEN-YEAR NETWORK DEVELOPMENT PLAN

47. The ESO shall develop and approve the TYNDP in cooperation with the ELTP Participants.
48. The TYNDP shall include the results of all studies as defined in the requirements of Chapter 8 of the ETN Code and shall summarize the activities necessary to ensure the further reliable and secure operation of the electricity system at economically justified least costs for each year out of the 10-year planning period, by the following aspects:
    1) Electricity and capacity demand and supply forecast;
    2) Capacity reserve requirements of power plants;

3) Technical parameters of the existing generating facilities, as well as decommissioning and reconstruction projects;
4) Description of newly expected generating capacities and the preferable nodes for their connection;
5) Description of Transmission Network development activities,
6) Electricity import and export forecasted volumes;
7) Electricity generation and consumption balance, including Transmission Network losses and electricity for own needs;
8) Surplus or deficit of electricity and capacity generation, as well as reserve requirements.

49. The Utility-Scale Plants, Transmitter, and Distributor shall include the activities specified in the TYNDP in the investment programs, in parts and periods regarding each of them.

50. After the necessary data and information is collected, processed, and summarized as defined in Chapter 7 of the ETN Code, before October 15, the ESO shall publish the draft TYNDP on its official website and send a notification to the RoA Government authority, Commission, and ELTP Participants.

51. Within 20 business days following the receipt of the notification from the ESO as defined in Provision 50 of the ETN Code, the RoA Government authorized body, Commission, and ELTP Participants shall submit their suggestions and opinions to the ESO.

52. Within 20 business days after the suggestions and opinions with regard to the draft TYNDP have been provided, the ESO shall summarize the presented suggestions and approve the TYNDP within 20 business days.

53. Within 5 business days following the approval, the ESO shall provide the approved TYNDP to the RoA Government authorized body and Commission and will publish it on the ESO website, notifying the ELTP Participants of that fact.

SECTION 3. SHORT-TERM PLANNING

CHAPTER 10. GENERAL PROVISIONS

54. The purpose of short-term planning is to plan the reliable and secure operation of the Electricity system on an annual basis.
55. During, short-term planning the following shall be considered:
    1) The annual schedule of the planned outages of the electricity system, including its adjustments on a monthly and daily basis (hereinafter, EPOS);
    2) The forecasted annual demand for electricity, including its adjustments on a monthly and daily basis (hereinafter, EDEM);
    3) The forecasted annual electricity generation mix, including its adjustments on a monthly and daily basis (hereinafter, EGEN);
    4) The forecasted annual Transmission Network losses, including their adjustments on a monthly and daily basis (hereinafter, ELTRANS);
    5) The annual reliability and security level of the electricity system, including its adjustments on a monthly and daily basis (hereinafter, ERSL).
56. The ESO shall collect, process, and summarize the data and information required for short-term planning. The list and reporting forms of data and information required for short-term planning to be submitted by relevant WEM Participants in compliance with the requirements of this Chapter shall be defined by the ESO.
57. The ESO may request additional information or clarifications from WEM Participants during short-term planning. WEM Participants shall provide additional clarifications to the ESO in procedures and within the deadline established in Chapter 3 of the ETN Code, unless a longer period is agreed upon by the parties.

CHAPTER 11. SCHEDULE FOR THE PLANNED OUTAGES

58. The ESO shall compile the EPOS based on the information on planned outages of electric facilities received from Utility-Scale Plants, the Transmitter, the Distributor (only for substations and electricity transmission lines directly connected to the Transmitter), and Utility-Scale Customers (hereinafter, ESTPO Participants).
59. The ESO shall compile the EPOS on an annual basis and shall adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
60. The ESTPO Participants shall provide the information on annual outages of their facilities for the following year to the ESO by June 1 of the given year, whereas the monthly and daily adjustments for annual information shall be provided as follows:
    1) By the 15th of every month for the following month;
    2) Each business day by 10:00 of the same day for the following second business day, and if following days are non-business days, for those days and the next following business day as well.
61. The ESTPO Participants' information on annual, monthly, and daily planned outages of their electric facilities submitted to the ESO shall include at least the following:
    1) Description of the electric facility subject to the planned outage;
    2) Duration of the planned outage;
    3) Planned outage start and end dates;
    4) Justification for the planned outage.
62. The EPOS shall be compiled and adjusted by the ESO based on the information submitted by the ESTPO Participants as prescribed in Provision 61 of the ETN Code, as well as information on outages for cross-border transmission lines received from neighboring Transmission Network operators.

63. The ESO, while compiling the EPOS, shall maintain the schedules for planned outages suggested by the ESTPO Participants, unless those negatively affect the RS Indicators of the electricity system.
64. The ESO shall submit the draft EPOS each year by July 15 to the ESTPO Participants for review.
65. Upon receipt of the draft EPOS, the ESTPO Participants shall provide their suggestions and comments to the ESO by August 15.
66. The ESO shall summarize the suggestions and comments received from the ESTPO Participants by September 1 of the current year and publish the EPOS in the MMS, notifying the Commission and ESTPO Participants about it.
67. The ESO shall summarize and publish in the MMS the monthly and daily adjusted data of the EPOS in the following timeframes:
    1) By the 25th of every month for the following month;
    2) Each business day by 12:00 of the same day for the following second day, and if the following days are non-business days, for those days and the next following business day as well.

CHAPTER 12. DEMAND FORECAST

68. The ESO shall compile the EDEM based on the demand forecast data provided by the Universal Supplier, the Distributor, the Supplier, Utility-Scale Customers, Utility-Scale Plants (hereinafter, EDEM Participants), and the results of the ESO analysis.
69. The ESO shall compile the EDEM on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
70. The EDEM Participants shall submit their demand forecasts to the ESO by October 1 each year for the following year and shall submit the adjusted monthly and daily forecasts of the annual demand within the periods defined in Provision 60, sub-Provisions 1 and 2 of the ETN Code, respectively.
71. The annual demand forecast submitted by the EDEM Participants to the ESO shall include:
    1) The annual demand forecast of electricity by months (MWh);
    2) The minimum and maximum active capacity demand by months (MW);
    3) The minimum and maximum reactive capacity demand by months (MVAr);
    4) The hourly load schedules for:
        a. Business days;
        b. Saturdays and Sundays;
        c. Public holidays and commemoration days.
    5) Demand-side management measures, if envisaged.
72. Monthly demand forecasts submitted by the EDEM Participants to the ESO shall include:
    1) The monthly demand forecast of electricity by days (MWh);
    2) The minimum and maximum active capacity demand by days of the given month (MW);
    3) The minimum and maximum reactive capacity demand by days of the given month (MVAr);
    4) The adjusted hourly load schedules for the given month in the format provided in Provision 71, sub-Provision 4) above:
    5) The adjustments to demand-side management measures for the given month, if envisaged.
73. The daily demand forecast submitted by the EDEM Participants to the ESO shall include:
    1) The hourly distribution of daily electricity demand (MWh);
    2) The hourly distribution of daily reactive capacity demand (MVAr).
74. The EDEM Participants' forecasts of annual, monthly, and daily demand shall be submitted for all WEM connection points grouped by connection points to Transmission and Distribution Networks and take into account any anticipated changes during the planning period.
75. The demand forecast data of the EDEM Participants do not include the Utility-Scale Plants' own needs except for the cases when electricity required for the own needs is planned to be purchased from the WEM.

76. The ESO shall compile the EDEM based on data mentioned in Provision 71 and, in case of monthly and daily adjustments, based on the data received from EDEM Participants according to Provisions 72 and 73 of the ETN Code respectively; it shall also consider the following:
    1) Expected GDP growth in the country;
    2) Potential impact of energy efficiency projects;
    3) Historical demand data;
    4) Forecast of Transmission Network losses;
    5) Possible impact of weather forecasts;
    6) Electricity forecasts for cross-border trade;
    7) Other information and factors that may have an impact on the EDEM.
77. The ESO shall compile the EDEM for the next year by November 1 of the given year, and the adjusted monthly and daily forecasts within the periods defined in Provision 67, sub-Provisions 1 and 2 of the ETN Code, respectively.

CHAPTER 13. GENERATION STRUCTURE FORECAST

78. The EGEN shall be compiled by the ESO based on the data provided by the Utility-Scale Plants and the results of the ESO analysis.
79. The ESO shall compile the EGEN on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
80. The Utility-Scale Plants shall provide to the ESO the hourly generation schedules forecasted for the following year for each generating unit by October 1 of each year, as well as:
    1) Each generating unit's maximum available capacity on a weekly basis;
    2) Delivery of electricity at each Connection point with the Transmission or Distribution Network.
81. Utility-Scale Plants shall adjust and submit to the ESO the information provided in Provision 80 of the ETN Code within the periods specified in Provision 60, sub-Provisions 1 and 2 of the ETN Code, respectively.
82. The ESO shall compile the EGEN based on the data submitted by Utility-Scale Plants in accordance with Provision 80 of the ETN Code to meet internal market demand at minimum cost, considering the following as well:
    1) The need for efficient use of the installed capacities of the Generators and historical data of generation volumes;
    2) Power purchase guarantees given to Generators;
    3) Entry of new generation capacities into the Electricity system and retirement of current generation capacities;
    4) Possible impact of weather forecasts;
    5) Possible impact of energy efficiency projects;
    6) Electricity system Reliability and Security indicators;
    7) Other information and factors that may have an impact on the EGEN.
83. The ESO shall compile the EGEN for the next year by November 1 of the given year, and the adjusted monthly and daily forecasts within the periods specified in Provision 67, sub-Provisions 1 and 2 of the ETN Code.
84. The ESO, while developing the EGEN, may change the forecasted hourly schedules of the electricity generation of IPP plants in order to bring to a minimum the annual expenses for electricity purchase by the Universal Supplier, discussing this with the Universal Supplier and IPP Plants. The Universal Supplier and IPP Plants shall be obliged to follow the EGEN recommended by the ESO.
85. The ESO, while making monthly and daily adjustments of the EGEN, shall inform the Utility-Scale Plants of differences in indicators if they differ from the indicators defined by the Commission for RPPs and IPPs in accordance with Provision 108 of the WEM Rules.

CHAPTER 14. TRANSMISSION NETWORK LOSS FORECAST

86. The ESO shall calculate the ELTRANS as the total sum of losses of Transmission Network facilities.
87. The ESO shall develop the ELTRANS on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this chapter.
88. The ESO shall calculate the ELTRANS based on the following:
    1) EDEM;
    2) EGEN;
    3) Forecasted cross-border electricity flows and electricity transits;
    4) Weather conditions;
    5) Transmission Network topology.
89. The ESO shall present in the ELTRANS the losses of the Transmission Network for the next year in an hourly manner and provide them to the Transmitter within the timeframes specified in Provision 90 of the ETN Code.
90. The ESO shall develop the ELTRANS for the next year by November 1 of the given year, and the monthly and daily adjustments within the periods specified in Provision 67, sub-Provisions 1 and 2 of the ETN Code, respectively.

CHAPTER 15. ELECTRICITY SYSTEM RELIABILITY AND SECURITY ASSESSMENT

91. The ESO shall assess the ERSL based on the data received from WEM Participants, as well as data stated in sub-accounts of the WEM Participants' e-cards involved in the MMS users' database platform in accordance with Transactions and the results of the ESO analysis.
92. The ERSL shall include the following analysis, implemented in accordance with Annex 1 of the ETN Code:
    1) Operational reliability and security of the Transmission Network assets and personnel;
    2) Operational reliability and security of the facilities connected to the Transmission Network;
    3) Operational reliability and security of the interconnection lines with the neighboring electricity systems;
    4) Security of the electricity supply to end-use customers:
        a. Active and reactive power generation/consumption;
        b. Sufficient control reserves of the electricity system;
    5) Static and Dynamic Stability of the electricity system.
93. The ESO shall assess the ERSL on an annual basis and adjust it for monthly and daily periods in accordance with the procedures defined in this Chapter.
94. For annual ERSL assessment, the ESO shall use the annual information on EPOS, EDEM, EGEN, and ELTRANS, as well as data on the import/export and transit of electricity provided by the EMO in accordance with Provision 99, sub-Provision 1 of the WEM Rules, taking into consideration the following:
    1) Historical operational data of the Electricity system;
    2) Interconnection operational data;
    3) Operational events notifications and operational conditions that could impact electricity system reliability and security;
    4) Transmission Network constraints that may impact the demand and generation forecasts;
    5) Fuel supply options;
    6) Weather forecast data;
    7) Information on events that may affect the reliability and security of the Electricity System.
95. The ERSL annual assessment shall be carried out every year by November 1 for the following calendar year. The ERSL shall be carried out for typical operational hours selected for analysis of the electricity system's reliability and security, defined by the ESO based on historical data and operational experience. The ERSL assessment shall contain, as a minimum, the following information:

1) Total demand forecast for each month, week, day, and hour;
2) Total available generation output for each month, week, day, and hour;
3) Transmission Network losses;
4) A description of any foreseeable situations, the occurrence of which may violate the RS Indicators;
5) A description of any foreseeable situations, the occurrence of which may result in an inadequate active power reserve margin;
6) The loss of load probability that represents the number of hours per year in relation to total hours when RS Indicators cannot be met using the available capacities, to determine additional capacity demand in the long term.

96. The ERSL monthly and daily adjustments shall be conducted taking into consideration the hourly data recorded on the Participants' virtual e-cards sub-accounts involved in the MMS users' database platform according to the WEM Transactions, as well as foreseeable changes in data applied by the ESO during the annual assessment within the following timeframes:
1) By the 25th day of each month for the following month, by hour;
2) By 12:00 of each day for the next second day, by hour;
3) Each day for the following day, as follows:
a. By 16:30, also based on the DAM results;
b. By 19:30, considering the Transaction Allocation of the WEM Participants, defined by Provision 171 of the WEM Rules.

97. The results of the annual ERSL assessment and its monthly and hourly adjustments shall be provided by the ESO to the Transmitter and BSP within the timeframes specified in Provisions 95 and 96 of the ETN Code, respectively. The daily results of the ERSL assessment shall be published by the ESO in the MMS as well, according to the timeframe defined in Provision 96, sub-Provision 3.b) of the ETN Code with notifications provided to the WEM Participants and the EMO.

SECTION 4. OPERATIONAL MANAGEMENT

CHAPTER 16. GENERAL PROVISIONS

98. Operational management aims to regulate actions of the ESO and the WEM Participants defined in this section to ensure reliable and secure operation of the electricity system.
99. The ESO and the following WEM Participants shall participate in the Operational management process (hereinafter, EOM Participants):
    1) Balancing Service Provider;
    2) Transmitter;
    3) Distributor;
    4) Utility-Scale Plants;
    5) Utility-Scale Customers.

CHAPTER 17. OPERATIONAL SUBORDINATION

100. In terms of operational subordination, all equipment and devices of the EOM Participants can be:
    1) Under Operational control and management of the ESO's dispatcher;
    2) Under Operational control of the ESO's dispatcher and under operational management of the staff on duty of the EOM Participant.
101. The ESO shall determine the list of equipment and devices of EOM Participants subject to transfer to its Operational control and management or Operational management, which transfer shall be formalized by December 1 of the given year based on the written consent that the EOM Participants provided to the ESO. If, based on the data submitted by the EOM Participant or following the ESO's own initiative, no changes are made to the list of equipment and devices agreed upon the previous year, then the list shall remain in effect for the next year. Further changes to the equipment and devices stated in the list shall be made as needed based on data submitted by the EOM Participants or upon the ESO's initiative.
102. All actions regarding equipment and devices under Operational control and management of the ESO's dispatcher shall be performed by the on-duty personnel of the EOM Participant through the instruction issued by the ESO's dispatcher. Individual instruction shall be given for each action.
103. Actions regarding the equipment and devices that are under the operational control of the dispatcher of the ESO and under the management of the staff on duty of the EOM Participant shall be performed by the staff on duty of the EOM Participant with permission of the dispatcher of the ESO.
104. The staff on duty of the EOM Participant shall immediately inform the dispatcher of the ESO about any defects of equipment and devices that are under operational subordination of the ESO's dispatcher and unacceptable deviations from the network parameters.
105. The staff on duty of the EOM Participant that is subordinate to the ESO's dispatcher shall report to the dispatcher of the ESO after its shift as well as by request of the latter at any moment provide information about the existing scheme, as well as about the condition, Regime parameters, existing shortfalls, planned repairs, and switching of equipment and devices under operational subordination of the Dispatcher of the ESO. After the report is completed, the clock of the energy object shall be adjusted according to the clock of the dispatching point of the ESO.
106. The staff on duty of the EOM Participants, in cases of absence from the workplace, can be replaced and the information about such replacement shall be submitted to the dispatcher of the ESO.
107. Each year before December 20, the EOM Participants shall exchange with the ESO the following information:
    1) The approved list of the employees who are entitled to conduct the operational conversations;
    2) The approved list of the operational personnel entitled to conduct operational conversations and carry out switching.

CHAPTER 18. OPERATIONAL COMMUNICATIONS

108. Operational communication between the ESO and EOM Participants shall be carried out to ensure reliable and secure operation of the electricity system.
109. Communication links used for operational communication shall be physically separated from other communication channels. Other communication channels may be used for operational communication when channels dedicated for this purpose are unavailable.
110. The EOM Participants shall install the Automated System for Technological Process Management (hereinafter, ASTPM) according to the requirements of "Technical rules for operation of facilities and networks" approved by the GoA Decision No. 1605N dated December 27, 2007. The minimum requirements for the data provided through the ASTPM shall be defined by the ESO.
111. According to the requirements of the "Technical rules for operation of facilities and networks" approved by the GoA Decision No. 1605N dated December 27, 2007, the ESO shall install an Automated System of Dispatch Control (hereinafter, SCADA).
112. The minimum requirements for the SCADA are set to:
    1) Ensure that the ESO receives data from the installation points of the SCADA and from the ASTPM of the EOM Participants;
    2) Ensure compliance with other Dispatch control devices of the ESO;
    3) Be protected from unauthorized access.
113. The technical requirements for communication channels of the EOM Participants shall be set by the ESO.
114. The ESO shall ensure the stable and high-quality functioning of the communication channel and eliminate any defects or faults identified as soon as possible, with the support of the EOM Participants.
115. The EOM Participants' dispatch centers must be equipped with a dedicated dispatch communication switchboard for voice data exchange in real-time operations.

CHAPTER 19. PREVENTION AND ELIMINATION OF EMERGENCY STATES

116. The ESO shall develop instructions for the post-contingency restoration of the electricity system, thus defining the coordinated actions of the ESO and the EOM Participants in emergency events. The ESO shall approve the instructions for post-contingency restoration and each year by December 1 shall inform the EOM Participants of changes therein.
117. Based on the post-contingency restoration instructions, within one month, the EOM Participants shall develop their own internal restoration instructions.
118. The ESO shall coordinate the actions of the EOM Participants aimed at post-contingency restoration of the system. The EOM Participants shall participate in the restoration of the system after the contingency event following their own internal restoration instructions and instructions from the ESO.
119. The ESO, in cooperation with EOM Participants, shall analyze system emergency states that took place in the electricity system and develop prevention programs.
120. In case of emergency outages of facilities in the electricity system, the EOM Participant shall immediately notify the ESO.
121. The ESO shall inform the Transmitter as soon as possible of the emergency disconnection of the Transmitter's equipment under its operational control.

CHAPTER 20. READINESS TESTING OF IPP PLANTS

122. In the frame of operational management, the ESO shall implement readiness testing to check the readiness of generating units of IPP Plants if a capacity charge is defined in the Public-Private Partnership (PPP) contracts concluded with them.
123. The ESO shall conduct post-repair readiness testing of IPP generating units on a mandatory basis and as needed. Results of the readiness testing shall be recorded by the ESO in the Readiness Testing Act.

124. While conducting readiness testing of IPP generating units, the parties shall be guided by procedures for technical maintenance, renovation, and testing defined in the "Technical rules for operation of facilities and networks" approved by the GoA Decision No. 1605N dated December 27, 2007 as well as the values of equipment rating as prescribed by the manufacturers of equipment (minimum and maximum levels of the capacity, ramp rates, and others), considering the changes that result after adjustment.
125. If a planned readiness test has not been conducted by the ESO within the period from 00:00 of the first day until 24:00 of the last day of the calendar month (hereinafter, the Settlement month), then the capacity specified in the contracts defined in Provision 60 of the WEM Rules as "Contract capacity" for that period shall be considered as the ready capacity of the generating units of the Utility-Scale IPP Plants.
126. Should a failure occur in the electricity system and the generating unit of the Utility-Scale IPP Plant is disconnected from the electricity system while conducting readiness testing or such testing could not proceed because, according to the opinion of the ESO, testing prevents recovery from the failure, then the testing shall be suspended by the instruction of the ESO and shall be considered not completed.
127. If the average capacity developed by a unit of the Utility-Scale IPP Plant during the readiness testing is 95 percent of the available quantity, the contractual quantity stated in Contracts defined in Provision 60 of the WEM Rules shall be approved by the Readiness Testing Act as the available capacity.
128. If, during the readiness testing:
    1) The generation capacity of the Utility-Scale IPP Plant generator cannot reach the Available capacity defined in Provision 127 of the ETN Code, or can reach it but cannot be kept at this level, then the average values recorded in the last hour for hydro units and the average value of the last 3 hours for the thermal units are set as the ready capacity in the Readiness Testing Act;
    2) The generator of the Utility-Scale IPP Plant is disconnected from the electricity system as an emergency, then 0 MW ready capacity is set in the Readiness Testing Act for the period until the next readiness testing.
129. If the Readiness Testing Act states a capacity lower than the Available capacity, then the Utility-Scale IPP Plant shall have a right to propose to the ESO additional readiness testing. The ESO shall conduct additional testing within 3 business days after receiving the application for such testing. Additional readiness testing shall be performed no more than once per Settlement month.
130. All Readiness Testing Acts shall be presented by the ESO to the EMO, the Universal Supplier, and the Utility-Scale IPP Plant before the first day of the month following the Settlement month.

CHAPTER 21. RELAY PROTECTION AND AUTOMATIC EMERGENCY CONTROL SYSTEM

131. The elements of the electricity system (generators, transformers, transmission lines, reactors, capacitors, and others) shall be equipped with Relay Protection and Automatic Emergency Control (hereinafter, RPAEC) devices, which are designed to respond to abnormal states of the system by disconnecting the failed element automatically by means of breakers.
132. Each year before November 1, the ESO shall submit to WEM Participants managing the RPAEC the following:
    1) Pre-settings for the RPAEC devices;
    2) Instructions to change the pre-settings of the RPAEC devices;
    3) Instructions to ground the neutral windings of the transformers.
133. The WEM Participants managing the RPAEC devices shall:
    1) Ensure the functioning of the RPAEC devices;
    2) Ensure the maintenance of any RPAEC devices located on their territory but owned by the ESO;
    3) Ensure the fulfillment of instructions received from the ESO on changing the pre-settings of the RPAEC devices within the period specified by the ESO and providing immediate notification to the ESO in writing;
    4) Ensure ad hoc inspection of RPAEC devices at the request of the ESO.
134. Each year before October 15, the WEM Participants managing the RPAEC devices shall submit for the ESO's approval the schedule of planned inspections for the next calendar year of the RPAEC devices

that are under the operational subordination of the ESO. The ESO shall review and, by November 1, submit its questions on these schedules to the WEM Participants managing the RPAEC devices. The WEM Participants managing the RPAEC devices shall submit their clarifications to the ESO questions by November 15 of the given year. The ESO shall summarize and, by December 1, approve the schedule of planned inspections of the RPAEC devices for the next calendar year.

135. The WEM Participants shall carry out the planned inspections of the RPAEC devices in accordance with the schedules approved by the ESO. If necessary, WEM Participants can carry out an unplanned inspection notifying the ESO about this at least 1 business day in advance.
136. The WEM Participants shall inform the ESO about the results of the planned and unplanned inspections of the RPAEC devices completed during the given month by the 5th business day of the next month.
137. In case it is necessary to install new or replace the existing RPAEC devices, the WEM Participants managing the RPAEC devices shall submit an application to the ESO in writing.
138. Within 10 business days from receipt of the application defined in Provision 137 of the ETN Code, the ESO shall approve it or provide comments and recommendations. Within 10 business days from receipt of comments and recommendations, as a result of discussions held between the ESO and the WEM Participant, the ESO shall approve or reject the submitted application, stating the justifications for rejection.
139. The WEM Participants managing the RPAEC devices shall immediately inform the ESO about RPAEC failures and eliminate malfunctions as soon as possible, informing the ESO.

CHAPTER 22. RELIABILITY OF ELECTRICITY SYSTEM OPERATION

140. The ESO shall take all actions defined by the ETN Code to maintain the RS Indicators.
141. The ESO shall provide access to EOM Participants about the information on its servers regarding the states and operational schemes of the Electricity System.
142. The ESO shall publish on its official website the reliability requirements for the devices and equipment for the next calendar year as described in Provision 101 of the ETN Code and, before December 15, inform the EOM Participants. Those requirements shall serve as a basis for the EOM Participants to implement corresponding measures aimed at ensuring RS Indicators.
143. Before the 20th of each month following each quarter of the calendar year, the EOM Participants shall present actual reliability data on their respective devices and equipment described in Provision 101 of the ETN Code to the ESO.
144. Each year before April 1, the ESO shall publish on its official internet site and inform the EOM Participants of the summary of the last year's actual reliability indicators for their respective Equipment and Devices specified in Provision 101 of the ETN Code, calculated according to RS Indicators.
145. The reliability indicator for electricity supply (delivery) at each Connection point of the electricity system shall be established in the Connection Contract and be specified, regardless of any limitations and their causes, as a ratio between the sum of annual hours delivering electricity at the given Connection point and the total hours per year and must be not less than 0.99. In case of deviation of the contract reliability indicator for supply (delivery) of electricity at the given Connection point of the electricity system, the responsibility to the connected person (including compensation for possible damages caused by the deviation) shall be borne by the Transmitter or Distributor depending on the Connection point. If unlawful actions (or inaction) of a third party are the immediate cause of such deviation, then the third party shall be proportionally responsible to the Transmitter and Distributor, depending on the Connection point, and the latter shall acquire a recourse right to the third party for the incurred amount.
146. The EOM Participants shall submit to the ESO a report on the actual level of reliability of the equipment and devices under the latter's operational control, within the terms and conditions specified by the ESO. After receiving the report, the ESO shall analyze the rules of the ETN Code and submit the results to the Commission by the last day of the month following each quarter.

SECTION 5. DISPATCH IN REAL TIME

CHAPTER 23. GENERAL PROVISIONS

147. The Dispatch is conducted by the ESO to ensure the reliable and secure operation of the electricity system in real time.

148. During the Dispatch, the ESO shall:
   1) Monitor the real-time cross-border and internal electricity flows;
   2) Control the operational functioning of equipment and devices under its operative subordination;
   3) Issue Dispatch instructions to the EOM Participants as appropriate to provide System services in cases defined in the ETN Code;
   4) Determine the availability of the necessary reserves at the BSP and activate these reserves by issuing Dispatch instructions;
   5) Prevent or eliminate congestion in the Transmission Network;
   6) Take all necessary actions to maintain an appropriate level of reliability and electricity quality, taking into account the requirements of the RS Indicators and technical regulations;
   7) Take all necessary actions to counteract Emergency Situations, as it is foreseen in the ETN Code and the WEM Rules.

149. In cases and procedures specified in the ETN Code, to ensure the RS Indicators in the process of dispatching, WEM Participants shall provide System services, which are classified as follows:
   1) Balancing and frequency control;
   2) Reactive power and voltage control;
   3) Electricity system black start in case of full system shutdown.

150. The ESO and the EOM Participants shall participate in the process of Dispatching Utility-Scale Plants;

151. The EOM Participants are subject to the ESO's Dispatch instructions in the following cases:
   1) In order to provide a balancing and frequency control System Service;
      a. The BSP, in terms of its Primary, Secondary, and Tertiary Reserve, and the Utility-Scale Plants, in terms of their Primary Reserve, are subject to Dispatch in Normal and Emergency States;
      b. All EOM Participants may be subject to dispatch in Emergency Situations.
   2) In order to provide the reactive power and voltage control System service, all EOM Participants are subject to Dispatch;
   3) In order to provide the black start System service after full system shutdown, the Utility-Scale Plants involved in the list for Activation specified in Provision 180 of the ETN Code are subject to Dispatch during the Emergency state.

152. The WEM Participants shall take all necessary measures to comply in real time with their Transactions and Transaction Allocation schemes, unless otherwise specified in this section of the ETN Code for the WEM Participants.

153. The ESO may change the Transaction Allocation of the BSP in order to ensure the RS Indicators.

154. During the dispatch, to ensure the reliable and safe operation of the electricity system in real time, the ESO shall perform congestion management in the Transmission Network in accordance with the requirements of Chapter 28 of the ETN Code.

155. The ESO and WEM Participants shall be guided by the requirements of Chapter 29 of the ETN Code in situations requiring unavoidable restrictions of electricity supply.

CHAPTER 24. REQUIREMENTS TO DISPATCH INSTRUCTIONS

156. The ESO shall carry out the Dispatch by issuing Dispatch instructions to the EOM Participants in cases provided for by Provision 151 of the ETN Code and to ensure the RS Indicators.

157. While issuing Dispatch instructions, the ESO shall take into consideration the following factors:
1) Difference between planned and actual electricity demand;
2) Difference between the planned and actual schedules of cross-border active power interchanges;
3) Availability of reserves for balancing purposes;
4) Technical restrictions per generating unit;
5) Changes in the Transmission Network configuration;
6) Changes in the Distribution Network affecting the quality indicators of electricity at Boundary Points of the Transmission and Distribution Networks;
7) Availability of the respective types of generating capacity reserves that guarantee the reliability and quality of electricity supply to customers during parallel operation and potential risks of electricity supply interruption;
8) The need to change the voltage schedules of power plant buses connected to the Transmission Network, or of the Transmission Network substation buses, to secure the required reserve of reactive power;
9) Changes in the generation schedules of generating units;
10) Changes in the schedules of generating units operating in a combined heat and electricity generation cycle;
11) Changes in the schedules of generating units using renewable sources for generation of electricity;
12) Occurrence of disturbances during electricity system operation;
13) Secure and reliable operation of the electricity system.

158. Depending on the implementation mode, the Dispatch instructions may be fulfilled:
1) By applying system automation;
2) By applying orders from operational dispatchers.

159. Depending on the control type, the Dispatch instructions may be:
1) Direct – using remote control facilities, both automatic and/or manual;
2) Indirect – through the shift operators at the remote end of the control loop.

160. Depending on the transmission facilities, the Dispatch instructions may be:
1) Electronic – using IT facilities for data exchange and communication;
2) Verbal – using the telephone.

161. The dispatch instruction shall define the action subject to implementation and the period. Dispatch instructions shall be formulated clearly to minimize the probability of misunderstanding and errors, in accordance with the list of dispatching abbreviations and notions approved by the Central Dispatch Service of the ESO. In case of introducing changes in the list of abbreviations and notions, the ESO shall inform the EOM Participants of that fact each year before December 1.

162. Once an instruction from the dispatcher of the ESO is received, the person on duty at the EOM Participant shall repeat it and receive confirmation. Each instruction given by the Dispatcher of the ESO to the person on duty at the EOM Participant and information about the fulfillment of such instructions shall be registered in the operational logbooks of the ESO dispatcher and the person on duty at the given EOM Participant. The person on duty shall immediately and strictly follow the Dispatch instruction and start carrying it out from the moment it is confirmed by the dispatcher of the ESO.

163. If the staff on duty at the EOM Participant considers the Dispatch instruction to be inconsistent with the requirements of the ETN Code, then it should immediately inform the dispatcher of the ESO and provide justifications. If the Dispatch instruction issued by the dispatcher of the ESO is confirmed, the staff on duty shall follow the instruction, making an appropriate record in the operational logbook. If fulfilling the Dispatch instruction issued by the dispatcher of the ESO is found to be impossible, the EOM Participant shall immediately inform the dispatcher of the ESO.

164. The ESO shall ensure that all Dispatch (operational) communications between him/her and the EOM Participants be automatically registered and archived using electronic devices. Archived Dispatch instructions shall be preserved for at least 3 years. The information may be provided to the EOM Participants based on their written request to the ESO within 7 days after receiving the request.

165. Upon the loss of communications and the impossibility of issuing and/or receiving Dispatch instructions:

1) The EOM Participants concerned shall undertake the actions required for restoration of communications;
2) Generating units shall follow active and reactive power and voltage values stated on the last available schedules;
3) The EOM Participants shall organize new communication routes and shall mutually inform each other.

CHAPTER 25. BALANCING AND FREQUENCY CONTROL IN REAL TIME

166. For balancing of supply and demand and frequency control in the electricity system in real time, in cases specified in the ETN Code, the ESO shall use the Primary, Secondary, and Tertiary Reserves of the BSP and Utility-Scale Plants.
167. The requirements for the Primary, Secondary, and Tertiary Reserves of the BSP and Utility-Scale Plants shall be set based on the RS Indicators, considering the technical parameters of the electric facilities of the latter. The ESO shall define the size of the reserves for the BSP and Utility-Scale Plants each year for the next year and shall inform the relevant participants by December 1.
168. For balancing and frequency control purposes, the ESO shall use the Primary Reserves of the BSP and Utility-Scale Plants while they operate synchronously with the electricity system. The Secondary and Tertiary Reserves in the electricity system shall be provided by the BSP and used as necessary following the Dispatch instructions of the ESO.
169. For balancing and frequency control purposes, the dispatcher of the ESO shall have the right to issue the following Dispatch instructions to the BSP:
    1. Instruction to start up, synchronize, or shut down the unit;
    2. Instruction to follow active and/or reactive capacity set points;
    3. Other instructions on activities of the BSP to maintain the reliability and security of the electricity system.
170. The dispatcher of the ESO shall have the right to issue the following instructions to the EOM Participants regarding the equipment or devices under its operative subordination:
    1. Instruction to switch on, switch off, put under load;
    2. Instruction to organize an unplanned check of overhead lines;
    3. Instruction to check the equipment and devices.
171. In the event that the reliability and security of the electricity system is violated or is at the risk of violation, or in cases requiring inevitable restrictions of electricity supply, or in force majeure situations, the ESO shall declare an Emergency Situation. In Emergency Situations, the ESO shall have the right to give Dispatcher instructions to the other EOM Participants, as specified in Provision 169 of the ETN Code.
172. The ESO shall, as soon as possible, inform the WEM Participants through the MMS about the start and end of the Emergency Situation.

CHAPTER 26. REACTIVE POWER AND VOLTAGE CONTROL IN REAL TIME

173. To provide voltage and reactive power control System service in the Electricity system, the ESO shall use:
    1) The generating capacities under control of the BSP;
    2) The generating units of Utility-Scale Plants;
    3) The Transmitter's voltage control equipment and devices;
    4) The Distributor's voltage control devices connected to the Transmission Network;
    5) Utility-Scale Customers voltage control devices connected to the Transmission Network.
174. The tolerable deviations from nominal voltages and their durations in the Transmission Network nodes for different voltage levels are defined in accordance with the RS Indicators.
175. To provide reactive power and voltage control System service at the Transmission Network, the

ESO may issue the following Dispatch instructions to the Transmitter:

1) Switching in/out of shunt reactors and capacitor banks directly connected to the Transmission Network;
2) Switching in/out of transmission lines;
3) Altering the tap positions of on-load transformer changer (OLTC) devices of transformers and auto-transformers;
4) Changing the mode of operation and voltage set point of synchronous and static var compensators.

176. To enable reactive power and voltage control in the Electricity system, the ESO will issue the following Dispatch instructions to the EOM Participants (except for the Transmitter):

1) Instruction to ensure the voltage setpoint;
2) Instruction to ensure the reactive power setpoint;
3) Instruction to increase or decrease the reactive power.

177. EOM Participants shall provide reactive power and voltage control System service in the Normal State of operation as long as the provision of the service does not require changing the generating unit active power. In the case of an Emergency Situation, the reactive power and voltage control System service shall be provided by the EOM Participants, despite the changes in active power, based on the Dispatch instructions of the ESO.

CHAPTER 27. ELECTRICITY SYSTEM BLACK START

178. For restoration of the Normal State in the electricity system after full blackout, the ESO shall involve the generating units of the Utility-Scale Plants (hereinafter, the Black Start Facility) that have the capability to start up and synchronize with the electricity system without the need for external electricity supplies.
179. Once a year, by October 1, the Utility-Scale Plants shall provide to the ESO their list of Black Start Facilities by generating unit.
180. The ESO shall examine the list of Black Start Facilities of the Utility-Scale Plants and approve it by November 1 by giving notice to the Commission and the Utility-Scale Plants possessing the Black Start Facilities. In the process of examining the list of Black Start Facilities of the Utility-Scale Plants, the ESO shall have the right to request additional information or to start these facilities in order to find out their ability to start up and synchronize after a full blackout of the electricity system without external voltage supply.

CHAPTER 28. CONGESTION MANAGEMENT

181. In the process of real-time operation of the electricity system, the ESO shall control the actual loading of the Electricity system elements, including interconnection transmission lines.
182. Once the Electricity System congestion is identified, the ESO shall undertake all necessary measures to solve the congestion and restore full Transmission Network transfer capability.
183. For congestion management in the Electricity system, the ESO may issue Dispatch instructions to the EOM Participants regarding the change of the Normal state configuration.

CHAPTER 29. UNAVOIDABLE LIMITATIONS OF ELECTRICITY SUPPLY

184. To prevent a frequency drop, which is the result of a change in the balance of active power, or to restore frequency levels, unavoidable limitations of the supply of WEM Participants (hereinafter, limitations of electricity supply) shall be implemented by using Automated frequency load shedding and Dispatch load shedding programs.
185. Principles of operation and pre-settings for Automated frequency load shedding and automated recloser devices shall be defined by the ESO based on the RS Indicators.
186. Limitations of electricity supply of the WEM Participants shall be implemented by the Automated and Dispatch load shedding programs that are compiled by the initiative of the ESO based on the RS

Indicators. After receiving the programs, the EOM Participants shall approve them and inform the ESO of the fact within 5 business days.

187. Automated and Dispatch load shedding programs shall be compiled considering the following obligatory requirements:
   1) Limitations of electricity supply up to the Fixed Technological and/or emergency capacity level fixed in the WEM contract;
   2) Limitations of electricity supply applied in accordance with the priorities set out in Article 49 of the Law based on the list of customers approved by the Government of the RoA;
   3) Limitations of electricity supply applied to all other WEM Participants.
188. If a WEM Participant connected to the Transmission Network is included in the Automated load shedding program, then the records regarding the order of priority for this participant shall be stated in the Acceptance of the WEM Contract.
189. The limitations of electricity supply of WEM Participants shall be eliminated in the following order:
   1) The WEM Participants as described in Provision 187, sub-Provisions 1 and 2 of the ETN Code;
   2) All other WEM Participants.
190. The duration of the continuous limitation of the electricity supply shall not exceed four hours.
191. The decision on the application of electricity supply limitation programs shall be made by the ESO. In such situations, the ESO can perform disconnections, informing the WEM Participants as soon as possible.
192. The Distributor, based on the instruction of the ESO, shall be obliged to limit the electricity supply of the customers connected to the Distribution Network.
193. The decision on the application of electricity supply limitation programs for customers connected to the Distribution Network shall be made by the Distributor, providing the ESO with information about the volumes of such limitations. Limitations of electricity supply shall be eliminated once agreed with the ESO.
194. During the application of limitations programs, the relationships between the ESO and the Distributor are defined by the EDN Code.

SECTION 6. CONNECTION OF NEW OR RECONSTRUCTED CAPACITIES TO THE TRANSMISSION NETWORK

CHAPTER 30. GENERAL PROVISIONS

195. The connection process regulation of new or reconstructed capacities aims to ensure non-discriminatory access to the Transmission Network.

196. The following WEM Participants (hereinafter, the Applicant) may connect to the Transmission Network:
   1) Generators;
   2) Distributor;
   3) Qualified Customers.

197. An Applicant aiming to be connected to the Transmission Network shall:
   1) Apply to receive Connection Reference, if applying to connect a power plant;
   2) Apply to develop Technical Conditions;
   3) Sign a Connection Contract;
   4) Receive a Connection Permit.

198. It is not permitted to demand that the Applicant make payments, provide compensation, submit information and documents, or burden them with obligations, unless they are defined by the ETN Code or other normative legal acts.

CHAPTER 31. RECEIPT OF CONNECTION REFERENCE

199. In order to receive a Connection Reference, the Applicant shall apply to the Transmitter, providing information on the facility name, location (address), connection or added intended capacity, and the voltage of the connection point, attaching a document certifying payment of the service fee defined in Provision 200 of the ETN Code.

200. In order to receive the Connection Reference, the Applicant shall pay a service fee to the Transmitter equal to 500,000 AMD (including VAT); of that amount, 250,000 AMD (including VAT) is transferred by the Transmitter to the ESO within 15 business days after receiving the amount.

201. Within 15 business days of the Applicant's application, the Transmitter shall check the application for compliance with the requirements set out in this chapter, and, if necessary, shall make corresponding adjustments together with the Applicant, and:
   1) in case of compliance with Provision 199 of the ETN Code, shall:
      a) Develop the draft of the Connection Reference;
      b) Submit the application and the draft of the Connection Reference to the ESO;
      c) Transfer to the ESO 250,000 AMD (including VAT) and submit the document certifying the payment.
   2) In case of non-compliance with Provision 199, shall return the application.

202. The payment mentioned in Provision 200 of the ETN Code is subject to return only if the application is rejected in accordance with Provision 201 of the ETN Code.

203. The Connection Reference shall be developed and provided based on the requirements of the technical regulations of the RoA to complete the works, ensuring the reliability level of the electricity supply of the Applicant with minimal costs.

204. The Connection Reference shall include at least:
   1) Name, Surname of the Applicant;
   2) Name, type, capacity, and location of the plant (region, community, settlement);
   3) Connection point to the Transmission Network, the required voltage level, and the length of the planned transmission line;
   4) Reasoned measures for strengthening the existing electrical network that meet the conditions

of the new connection (increase in the cross-sectional area of the wires, replacement of power transformers, installation of additional cells, etc.);

5) Term of the Connection Reference.

205. The term of the Connection Reference shall be 6 months, starting from the moment that notification is presented in the appropriate manner.

206. The term of the Connection Reference can be extended only once. To extend the term, the Applicant shall submit an application to the Transmitter not earlier than 5 business days prior to the expiration of the term, paying 250,000 AMD (including VAT). In this case, the Transmitter shall extend the term for another 6 months. The application submitted later than set in this Provision shall be subject to rejection. The Transmitter shall inform the ESO of all applications and rejections.

207. Within 20 business days of receiving the information submitted by the Transmitter, the ESO shall study the impact of the Connection Capacity on the RS Indicators, assess the draft Connection Reference together with the Transmitter from the perspective of integrity and the necessity of measures aimed at implementation of necessary changes in Connection Capacity and Transmission Network, and present to the Transmitter the agreed draft of the Connection Reference.

208. The Transmitter shall issue a Connection Reference within 40 business days from receiving from the Applicant the complete information (documents) prescribed in Provision 199 of the ETN Code.

209. During the whole term of the Connection Reference, the capacity mentioned in the Connection Reference at the Connection Point fixed there shall be considered to be reserved for the Applicant. If an electricity generation license is being issued, the capacity of a power plant in the Transmission Network at the Connection Point fixed in the Connection Reference shall be considered to be reserved until the issuance of Technical Conditions.

210. In order to receive a new Connection Reference in case of the expiration of its term, the Applicant shall have the right to apply to the Transmitter for a second time in accordance with the procedure envisaged by the ETN Code.

211. If an electricity generation license is being issued during the effective term of the Connection Reference, Technical Conditions shall be issued to the Applicant in accordance with the Connection Reference if nothing else is agreed between the parties.

CHAPTER 32. DEVELOPMENT OF TECHNICAL CONDITIONS

212. In order to develop the Transmission Conditions, the Applicant shall submit the application to the Transmitter in accordance with Annex 3 of the ETN Code and attach the following:

1) Documents certifying (proving) his/her rights or acquisition of rights to the area of the Connection Capacity;

2) A document certifying payment to the Transmitter for providing the Technical Conditions.

213. In order to receive the Technical Conditions, the Applicant shall pay a service fee to the Transmitter equal to 500,000 AMD (including VAT), except for the case when the Applicant has reserved capacity prescribed in Provision 209 of the ETN Code. In such cases, to receive the Technical Conditions, the Applicant shall pay a service fee to the Transmitter equal to 50,000 AMD (including VAT).

214. Within 15 business days of the Applicant's application, the Transmitter shall check the application for compliance with the requirements set out in this chapterand, if necessary, make corresponding adjustments together with the Applicant, and

1) In case of compliance with Provision 212 of the ETN Code, shall:

a) Develop the draft of the Technical Conditions based on the requirements of the technical regulations, and in case the Applicant has the effective Connection Reference, based on the Connection Reference as well;

b) Submit the application and the draft of the Technical Conditions to the ESO;

c) Transfer to the ESO 250,000 AMD (including VAT) and submit the document certifying the payment, except for the case when the Applicant has reserved capacity prescribed in Provision 209 of the ETN Code.

2) In case of non-compliance with Provision 212 of the ETN Code, shall return the application.

215. Within 15 business days of receiving the information submitted by the Transmitter, the ESO shall study the impact of the Connection Capacity on the RS Indicators, assess the draft Technical Conditions together with the Transmitter from the perspective of integrity and the necessity of measures aimed at implementing necessary changes in Connection Capacity and Transmission Network, and present to the Transmitter the agreed draft of the Technical Conditions.

CHAPTER 33. CONNECTION FEE

216. The Connection Fee shall be calculated and the amount shall be determined by the Transmitter based on the agreed draft of the Technical Conditions in order to compensate expenses necessary for ensuring the connection of the Connection Capacity to the Transmission Network.
217. The Connection Fee shall be calculated within 15 business days after receipt of the agreed draft of the Technical Conditions in accordance with Provision 215 of the ETN Code. The amount of the Connection Fee shall be determined based on expenses for similar designs and is subject to adjustment in the design stage.
218. The Connection Fee for connection of the Connection Capacity to the Transmission Network shall include the sum of expenses required for construction of new capacities, modification of existing capacities, purchase and installation of the metering device as well as the equipment and software required for the connection to the DAS, and other services that are deemed necessary for connection purposes as described in the ETN Code and other technical regulations, including expenses for design.

CHAPTER 34. CONNECTION CONTRACT

219. Within 10 business days after calculation of the Connection Fee, the Transmitter shall provide the Applicant with the solely signed (verified) draft Connection Contract attaching the draft of the Technical Conditions and calculation of the Connection Fee (agreed with the ESO), which are considered to be an integral part of the Connection Contract.
220. The Applicant shall sign (verify) the solely signed (verified) Connection Contract and return it to the Transmitter within 6 months after receipt. A contract presented later than this has no legal force.
221. Within 5 business days after receiving the signed (verified) copy of the Connection Contract from the Applicant, the Transmitter shall inform the ESO.
222. The Connection Contract shall include the following:
    1) Deadline for submission of the examined connection design to the Transmitter for approval;
    2) Deadline for approval of the connection design presented for the Transmitter's approval by the ESO and EMO;
    3) Estimated amount of the Connection Fee and schedule for payments (timeline), as well as the mechanisms for adjusting the initial and final amounts of the Connection Fee;
    4) Date for connecting the capacity to the Transmission Network and responsibilities of participants in case of a breach of the terms.
223. Any change in the Connection Contract agreed between the parties shall be done according to the procedures and deadlines prescribed in the Connection Contract (if otherwise is not specified by the Connection Contract).

224. Within the scope of the Connection Contract, the reconstructed as well as newly constructed capacities in the Transmission Network shall be considered the property of the Transmitter, while the metering device as well as other equipment and software necessary to connect to the DAS shall be the property of the Applicant.
225. Control over fulfillment of the Contract shall be performed solely by the contracting parties.

CHAPTER 35. CONNECTION PERMISSION

226. To obtain Connection Permission, the Applicant shall submit the following documents to the Transmitter at least 40 business days in advance of the connection date mentioned in the Connection Contract:
    1) A copy of the construction completion document as it is provided for by the legislation of the RoA;
    2) A copy of the conclusion (permission) of the assessment made on the given capacity issued by the state body authorized to implement technical inspections;
    3) Information required as described in Annex 4 of the ETN Code;
    4) Plan of actions for connection.
227. The Transmitter, within 10 business days, shall check the compliance of the information submitted by the Applicant according to the requirements set in Provision 226 of the ETN Code and shall submit the plan of action for connection to the ESO for agreement.
228. Upon receiving all necessary information from the Transmitter, the ESO shall agree with the plan of actions for connection within 10 business days.
229. After receiving the ESO's agreement, the Transmitter shall issue the Connection Permission to the Applicant (in case the conclusion is positive) or inform them of any non-compliance identified (in case the conclusion is negative) within 10 business days. If an identified non-compliance is not eliminated by the Applicant within 10 business days, the connection permission shall not be issued, and the connection date mentioned in the Connection Contract shall be extended according to the number of days of the delay.
230. Within 5 business days after receiving the Connection Permission, the Applicant shall inform the Transmitter and the ESO in writing about the preferred date for the actual connection of the Connecting Capacity to the grid.
231. If, in the ESO's opinion, the preferred date for the actual connection (launching or testing) mentioned by the Applicant is not acceptable in terms of ensuring the reliability and security of the operation of the electricity system, then within 3 business days, the ESO shall negotiate with the Applicant to change the connection date (launching or testing).
232. Connecting the Connection Capacity to the Transmission Network shall be carried out as per the plan of action for connection mentioned in Provision 228 of the ETN Code.
233. The Applicant shall test its Connection Capacity connected to the Transmission Network in order to confirm the compliance of that Connected Capacity with the terms mentioned in the Connection Contract. Such testing shall be performed in accordance with the plan of action agreed with the ESO.

SECTION 7. ELECTRICITY METERING REQUIREMENTS

CHAPTER 36. GENERAL PROVISION

234. The requirements for electricity metering in the WEM are intended to ensure the integrity, continuity, transparency, and uniformity of the Commercial Metering.

235. Electricity metering in the WEM shall be implemented by the EMO through the DAS and the Distributor's automated system of electricity metering.

236. The Metering Point of the WEM Participant shall be equipped with a Metering Complex and registered by the EMO in the DAS. The Metering Complex shall ensure:
   1) Metering of active and reactive components of electricity;
   2) The compliance of the accuracy class of the elements of the Metering Complexes with the requirements of Chapter 38 of the ETN Code;
   3) The transfer of metered data in electronic form to the metering database.

237. Expenses related to the acquisition, installation, replacement, maintenance, repair, inspection, and verification of the Metering Complex and other components of the DAM under the management of the WEM, as well as the responsibility for maintaining the integrity of the Metering Complex are borne by the possessor.

238. The EMO shall carry out Commercial metering at all Boundary points of the WEM Participants as well as at Import and Export points. Metering shall be conducted in such a manner to ensure:
   1) Determination of the amount of electricity generated by the Generators, and for Utility-Scale Plants differentiated by each Generator, the amount of electricity for own needs, and the amount of electricity supplied;
   2) Determination of the amounts of electricity transferred or transited via the Transmission Network;
   3) Determination of the amount of electricity supplied to the Distribution Network as well as the amounts of energy supplied from the Distributor's network to the network of the Transmitter and to Generators;
   4) Determination of the amount of electricity delivered to the WEM Participants;
   5) Determination of the amounts of electricity imported and exported.

239. The WEM Participants shall not interfere with the functioning of any element of their Metering Complexes, any metering data recorded, or the hourly reading of the electricity meter.

CHAPTER 37. GENERAL CHARACTERISTIC OF THE DAS

240. The DAS shall include the following:
   1) Metering Complexes;
   2) Primary data collecting server (communication server);
   3) Data processing and settlement server (main server);
   4) Nodal servers (data collection and transferring servers) or converters and devices for direct reading of meters by fiber optic cable or mobile connection, which are installed at substations and generating plants;
   5) Plant and substation servers, which are located at the control centers of Generators (including HPP cascades) and the Transmitter;
   6) Portable computers, which are used to import data to the database in cases where communication is disrupted or if the facility where the Metering Complex is installed has no telecommunication device;
   7) Database for nodal and regional level servers;
   8) Telecommunication infrastructure, including communication channels, local and large-scale computer networks, modems, converters, commutators, switches, managing and supporting software packages, etc.

241. The DAS shall ensure:
    1) Electronic data transfer to the settlement database;
    2) Registration of data received from Metering Complexes and its proper protection;
    3) Registration and availability of information in the data collection and transmission device (hereinafter DCTD) database regarding Generators, Transmitter, Distributor, and Qualified Customers;
    4) The amount of electricity recorded at each WEM Metering point and calculated per Boundary point.
242. Requirements for the servers and parameters of computers as well as software involved in the DAS shall be set by the EMO and published on its official website.
243. Commercial and control meters of the electricity involved in the DAS shall comply with the requirements set in the RoA for static meters for Commercial metering with IEC11070P (optical port) and RS485 interface, which are included in the list of the EMO software-supported devices and are published on the official website of the EMO.
244. The metering database shall include the following information:
    1) Recording of active and reactive energy and power passed through the Metering point counted as integral at 30-minute metering intervals, as well as the value of the power coefficient during the mentioned interval;
    2) Information about any changes made to the database and the person who made them;
    3) Information about each element of the electricity Metering Complex (voltage and current transformers, technical parameters of the meters, calibration data, manufacturing number, etc.).
245. In case of replacement of the Metering Complex, all newly installed meter data shall be entered into the database by the EMO.
246. The DAS shall be managed by the DAS Chief Administrator through the DAS Administrators.
247. The EMO shall ensure the availability of the DAS for each DAS Administrator per their applicability and shall inform each DAS administrator about the changes in software packages, technical-security requirements, or data related to the latter no later than 2 business days after making them.
248. The DAS Chief Administrator may reprogram the electricity meter if a software error is detected as a result of a self-diagnosis.
249. The DAS Chief Administrator may establish balance settlement groups in the DCTD in accordance with the settlement groups set up on the main server.
250. The EMO and WEM Participants shall be responsible for maintaining the confidentiality of passwords used in the DAS.
251. The DAS Chief Administrator and DAS Administrators shall be required to archive the database of the main regional servers under their responsibility at least once every 3 months.

CHAPTER 38. REQUIREMENTS FOR METERING COMPLEXES

252. A WEM Participant's Metering Complex shall be installed at the Boundary point; in cases when it is sufficiently justified and approved by the EMO, it can be installed beyond the Boundary point, such that the electricity technological losses occurring at the facilities located between the point of installation of the Metering Complex and the Boundary point are negligible for the contracting parties.
253. The WEM Participants, based on their actual electrical connections and Boundary points, shall decide on the location of electricity commercial and control Metering Complexes, to be agreed with the EMO.
254. The Metering Complexes shall be installed so as to:
    1) Form an electricity commercial settlement based on meter readings, without applying calculated losses of electricity;
    2) Minimize mechanical damage as well as unacceptable environmental impact;
    3) Minimize unauthorized interference to the connection scheme and the work of Metering Complexes;
    4) Make both commercial and control meter readings visible to the representatives of the contract parties and to the representative of the EMO;

5) Properly maintain the Metering Complex;
6) Ensure the safety of people's life and health.

255. The functions related to the installation, replacement, maintenance, performance testing, and calibration of the Metering Complexes shall be coordinated by the EMO.

256. The calibration of the metering device or its individual elements shall be conducted by the company responsible for implementing metrological control in accordance with the legislation of the RoA (hereinafter, Metrological Body), using the means of the managing company.

257. The installation and replacement of Metering Complexes or their individual elements shall be implemented with the participation of the managing company of the Metering Complex, Transmitter, or Distributor respectively (depending on which network is connected to the given WEM Participant) and the EMO by compiling a tripartite act in accordance with Annex 5 of the ETN Code. In this case, the managing company shall ensure that alternative equivalent metering data are transferred to the EMO.

258. The terminal clamps, metering transformers, or doors of their electrical panels or of cabinets shall be sealed and seals removed by the EMO in participation with the managing company of the given Metering Complex and the Transmitter or Distributor respectively (depending on which network the given WEM Participant is connected to) by compiling a tripartite protocol in accordance with Annex 6 of the ETN Code. To eliminate any emergency that occurs in the Metering Complex, the seals can be removed by the managing company of the Metering Complex, immediately informing the EMO and the other party about this. In such cases, the reseal of the Metering Complex shall be carried out as prescribed in this provision within 72 hours.

259. The requirements for the Metering Complexes, parameters of their individual elements, accuracy and accuracy testing of the meters and measuring transformers, and secondary circuits of the facilities shall comply with the technical regulations effective in the RoA, particularly:
1) Secondary circuits of the electrical facilities—management, signal, control, automation and relay protection circuits, and measuring transformers—shall operate jointly with the electrical circuits in accordance with the requirements of the technical regulation "Requirements for electrical facilities protection and automation device" adopted as the GoA decision No. 42-N dated January 17, 2008.
2) The commercial and control meters shall be installed in accordance with the requirements of the technical regulation "Technical requirements to the electrical equipment of the special facilities" adopted as the GoA decision No. 75-N dated January 15, 2009.
3) The measurements of the electrical parameters and accuracy classes of the measuring devices shall comply with the requirements of the technical regulation "Requirement to the devices of the electrical facilities" adopted as the GoA decision No. 1943-N dated December 21, 2006.
4) The static meters for watt-hours of the active energy of the alternative current shall meet the technical requirements established by the Ministry of Energy Order No. 96-ZD dated June 22, 1999 "On approval of technical requirements to the static meters for watt-hours of the active energy of the alternating current of 50Hz allowed to use in the electricity metering system of the Republic of Armenia."

CHAPTER 39. METERING DATA COLLECTION AND PERIODICITY

260. Metering data collection shall be implemented by the EMO through the DAS and the Distributor's automated system for electricity metering.

261. The Distributor shall ensure EMO access to the data of WEM Participants from the Distributor's automated system of electricity metering, in accordance with the EDN Code.

262. In order to collect the metering data of the DAS, the EMO shall ensure the workable state of the system-level server, the main server, and DCTD software packages and ensure data collection from DCTD to the system-level server.

263. The DAS (meters and servers) clocks shall be periodically checked so that they are synchronized with the effective time in the RoA.
264. The WEM Participant shall ensure that the DCTD collects of data registered in the meters of the Metering Complexes that they manage.
265. The EMO shall ensure Metering data collection through the DAS for every Settlement Period of the Trading Day as of 24:00.
266. In the middle and at the end of a calendar month, the EMO shall compile the actual hourly balance of the electricity system by Boundary points and Metering points within 6 calendar days.
267. For the development of the actual hourly balance of electricity, agreed metering settlement groups between the WEM Participants shall serve as a basis; these groups shall be repeated without changes in the system and regional servers. Any change in these settlement groups shall be carried out only with the agreement of the parties.

CHAPTER 40. CHECKING METERING COMPLEXES AND ELECTRICITY RECONCILIATION

268. For metering data verification, the EMO shall:
    1) Conduct a visual inspection of the Metering Complex at least once during the calendar year to check the integrity of the Metering Complex and availability of seals with the participation of the managing company of the Metering Complex and the Transmitter or Distributor respectively (to which network the given WEM Participant is connected);
    2) Compile balance groups from the meters involved in the Metering Complexes and consider the electricity balance formed in these groups at least once during the month. In case the electricity balance deviation in the balance group exceeds the limit values of the average statistical data for the last year or the allowable imbalance limit values defined in "Methodology for calculation of unavoidable losses of electricity in 110 kV and above networks" approved by the resolution of the RoA Energy Regulatory Commission dated November 19, 2001, then the EMO shall inform the party managing the Metering Complex of the imbalance as soon as possible, and the parties shall implement a visual inspection according to a mutually agreed procedure and timeline.
269. The EMO and the managing company of the Metering Complex and the Transmitter or Distributor respectively (to which network the given WEM Participant is connected) shall document the results of the visual inspection in the respective protocol, in accordance with Annex 7 of the ETN Code.
270. In a case when the visual inspection reveals that the integrity of the Metering Complex is damaged (current and potential transformer, meters, or separate details are broken or non-functional, seals are injured or removed or tampered with, secondary circuit wires are broken, the design-based electric circuit is changed, or the Metering Complex is in any way tampered with), it shall be presented to the Metrological Body in the procedure and timeframe mutually agreed among the parties with the aim to conduct an extraordinary calibration of the Metering Complex—meters, current and potential transformers.
271. Extraordinary calibration of the Metering Complex—meters, current and potential transformers—shall be conducted in accordance with Provision 256 of the ETN Code.
272. When an integrity failure of the Metering Complex is not detected during the visual inspection, and:
    1) The imbalance is beyond the statistical data, but is in the allowable imbalance limit range, such deviation shall be deemed acceptable and recalculations shall not be performed.
    2) The imbalance is outside the allowable imbalance limit range, such deviation shall be presented to the Metrological Body in the procedure and timeframe agreed mutually among the parties with the aim to conduct an extraordinary calibration of the Metering Complex—meters, current and potential transformers.

273. In cases prescribed in Provision 270 and Provision 272 sub-Provision 2) of the ETN Code, the EMO shall recalculate the electricity, compiling a relevant protocol (act) on the results of the recalculation. Recalculation shall be performed based on the data of the control meters for the calendar month when the Commercial metering failure is detected. If the recalculation is not possible to perform based on the data of the control meters, the EMO shall perform it based on the other Metering Complexes involved in the DAS, data of their balance groups, and conclusion issued by the Metrological Body. In such a case, the conclusion of the Metrological Body shall include data on the integrity of or damage to the devices that are part of the Metering Complex, on meter readings as well as on the results of the accuracy check of their performance.
274. If the integrity failure of the Meter Complex is detected by the managing company of the Metering Complex or the Transmitter or Distributor respectively (to which network the given WEM Participant is connected), the latter shall inform the EMO by the end of the next business day starting from the failure detection moment and be guided by the EMO's instructions, making records in the respective logbook. In the case described in this Provision, the parties shall be managed by procedures prescribed in Provision 273 of the ETN Code within 72 hours.
275. To check its metering data, the WEM Participant shall have a right to enter the territory of another WEM Participant, with prior consent of the latter, to read its data from the Metering Complexes.

ANNEX 1: RELIABILITY AND SECURITY INDICATORS

CHAPTER 1. GENERAL PROVISIONS

1. The Reliability and Security Indicators (RSI) shall describe the reliability and security of the Electricity System.
2. The indicators shall be classified into the following groups:
   1) RSI by states of the Electricity System,
   2) RSI by voltage,
   3) RSI by capacity reserves,
   4) RSI by static and dynamic stability,
   5) RSI by automated regulation systems,
   6) RSI by system automation control:

CHAPTER 2. PERFORMANCE OF RSI BY STATES OF THE ELECTRICITY SYSTEM

3. Assessment of performance of RSI shall be carried out for the following states in the Electricity system:
   1) Nk: Normal states of the Electricity System, when the elements k = 0, 1, 2, 3... are under repair;
   2) Nk-1 Normative contingencies.

4. Normative Contingencies are classified into the following groups:
   1) Group I – the most frequently occurring contingencies, which include:

      a. Emergency outage of a network element as a result of unsuccessful action of the Automatic Recloser (ARC), except for the outage of busbars, outage of the intersystem connection lines as a result of unsuccessful action of the Single-phase Automatic Recloser (SFARC), outage of one connection at the cross-section of the Electricity System due to unsuccessful ARC action;

      b. Emergency outage of a generation unit of up to 250 MW of installed capacity.

   2) Group II - Exceptional contingencies, which include:

      a. Emergency outage of double-circuit transit transmission lines (TL) by means of unsuccessful ARC action,

      b. Emergency outage of any of the busbars of the distribution facility at a power plant or a sub-station,

      c. Contingency shutdown of a reactor unit or of a generation unit of a power plant, the installed capacity of which exceeds 250 MW.

   3) Group III - Extraordinary contingencies, which include:

      a) Simultaneous outage of two and more independent TLs, by means of unsuccessful ARC action,

      b) Emergency outage of two busbars of a distribution facility at a power plant or a sub-station.

5. The RSI and requirements for their performance by states are introduced in the below table:

RSI	**Requirement for the performance of RSI by states of the Electricity System**			

	N_k (N_1 , N_2 , ..., N_k)	N_{K-1} (Group I)	N_{K-1} (Group II)	N_{K-1} (Group III)
1	2	3	4	5
1) Ensuring electricity supply according to demand (reliability indicator)	I	I	III	III
2) Ensuring necessary capacity reserve of the system (primary, secondary, and tertiary) (reliability indicator)	I	II	III	III
3) RSI by frequency: a) Ensuring quality of electricity (reliability indicator) · Long-term· Short-term	 I I	 II I	 III III	 III III
b) Ensuring stability of the Electricity System (security indicator) · Long-term · Short-term	 I I	 I I	 II II	 c
c) Ensuring security of elements of or electric installations connected to the Electricity System (security indicator) · Long-term · Short-term	 I I	 I I	 II II	 III III
4) Performance of RSI by voltage: a) Ensuring settlement values of voltage at boundary points of the Electricity System (reliability indicator) · Long-term · Short-term	 I I	 II I	 III III	 III III
b) Ensuring static stability of load at nodes of the Electricity System (security indicator) · Long-term · Short-term	 I I	 I I	 II II	 III III
c) Ensuring security of elements of the Electricity System or electric installations connected to the Electricity System · Long-term · Short-term	 I I	 I I	 II II	 II II

5) Ensuring static and dynamic stability of the Electricity System (security indicator) · Long-term · Short-term	I I	I I	II II	III III

6. In Point 5 of this Annex in case of the sign "I' maintenance of the given Indicator is mandatory without application of automated measures or interference of the ESO Dispatcher, in case of the sign "II" maintenance of the Indicator is mandatory with application of automated measures or interference of the ESO Dispatcher, and in case of the sign "III" maintenance of the Indicator is not mandatory.

CHAPTER 3. RELIABILITY AND SECURITY INDICATORS OF ELECTRICITY SYSTEM BY FREQUENCY

7. The performance of RSI of the Electricity System by frequency in cases prescribed by the ETN Code is ensured through primary, secondary, and tertiary regulation of frequency as well as operation of control systems.
8. To ensure the reliability of the Electricity System, the following permitted ranges of frequency change are set:

Range of permitted change of frequency	**Indicators, Hz**	
1) Long-term	50±0.1 no less than 95% of the week time	
2) Short-term	50±0.2 no less than 98.5% of the week time	
3) Maximum dynamic change range after Group I contingency (load shedding must not respond)	50±0.8	
4) Permissible range after Group I contingency	50±0.4 no more than 15 minutes	

9. To ensure security of the Electricity System, the following permitted ranges of frequency change are set:

Range of permitted changes of frequency	**Indicators in Hz**
1) Long-term	49.0–50.4

2) Short-term	48.0– 49.0 for 2 minutes 47.7 – 48.0 < 30 seconds 47.5 - 47.7 < 4 seconds < 47.5 must be excluded f≤49.0-49.5 Hz and $\frac{df}{dt} \geq 2 - -2.5 \frac{Hz}{sec}$ for 0.1seconds, 50.5-51.0 for < 3 minutes, 51,0-52,5 *for the time set according to the factory instructions for turbines* >52.5 - must be excluded

CHAPTER 4. RELIABILITY AND SECURITY INDICATORS BY VOLTAGE

10. $_k$ In a Nk situation, the voltages at the nodes of the Electricity System shall be regulated considering the^k potential occurrence of any N -1 normative contingency (Group I N_k -1, Group II N_k-1, and Group III N_k-1 contingencies)
11. To ensure the reliability of the Electricity System during Group I N_k and N_k-1 contingencies, the voltage regulation and control must be made through the control points of the Electricity System by the ESO.
12. To ensure the security of the Electricity System during N_k and N_k-1 situations (any Normative contingency, the voltage value in each load node shall ensure the static stability of the load by voltage a where:

$$K_U = \frac{U - U_{cr}}{U}$$

U – the voltage level at the load node under the given regime of the Electricity System.
U_{cr} – the critical voltage at the load node, which corresponds to the marginal value of static stability of electric engines. At nodes of 110 kV and higher voltage burden, the critical voltage accepted is not less than 0.7 and 0.75 U_{nom} , unless other more accurate data is available.

13. The requirements for static stability of the load in the Electricity System are as follows:
    1) The static stability *U* of the load should be not less than 15 percent for a N_k situation in the Electricity System, and not less than 10 percent in any N_k - *1* (any Normative contingency).

2) In the case of Group I N_k and N_k-1 contingencies in the Electricity System, the static stability shall be maintained by voltage level at each load node without the application of system automation control measures, and in the event of Group II N_k -1 contingencies, with the application of system automation control.

14. Security of equipment of the Electricity System with regard to voltage increase must be ensured. Voltage levels at the nodes should not exceed the maximum long-term permissible operating voltage levels for that equipment, and the short-term permissible voltage jump should not exceed the duration limits defined for that equipment.

CHAPTER 5. RELIABILITY INDICATORS OF THE ELECTRICITY SYSTEM BY CAPACITY RESERVES

15. If imbalances occur between generated and consumed capacities, frequency and capacity regulation shall be implemented through the involvement of primary, secondary, and tertiary capacity reserves as defined in the ETN Code.
16. The primary reserve capacity of the synchronous zone is planned for automatic restoration of the balance between generation and consumption after the emergency outage of the largest unit, thus preventing automated load shedding by frequency. The Electricity System primary reserve is intended to participate proportionally in the formation of the primary reserve of the synchronous zone in order to participate in the process of general frequency regulation of the synchronous zone or to ensure frequency regulation in the isolated zone of the Electricity System.
17. Indicators of the primary reserve capacity are the following:
    1) The minimum primary capacity reserve of the synchronous zone ($\Delta P^{I}_{s.z.r.}$) must be no less than the capacity of the largest unit of that synchronous zone,
    2) The minimum primary capacity reserve $(\Delta P^{I}_{\text{h}})$ within the synchronous zone of the Armenian Electricity System should be no less than the amount determined by the proportional principle as follows:

$$\Delta P^{I}_{\text{h}} \geq \Delta P^{I}_{s.z.r.} \frac{P_{\text{h}}}{P_{s.z.}},$$

where P_h, $P_{s.z.}$ are active capacity generation of the Electricity System and synchronous zone, respectively.

    3) In a situation that occurs due to the contingency outage of the largest unit of the synchronous zone and frequency regulation, the primary reserve capacity must be fully utilized for 30 seconds and 50 percent of that for 15 seconds.
    4) The units (generators) supplying the primary reserve capacity must be capable of providing such supply for at least 15 minutes.
    5) In the case of isolated mode of Electricity System operation, the ESO shall decide on the requirement for and the size of the primary reserve capacity to be involved.
18. The secondary capacity reserve aims to recover the used primary reserve capacity, the planned intersystem flow, and frequency within minutes after Group I contingency.
19. The indicators for secondary reserve are as follows:
    1) The minimum size of secondary reserve capacity must be sufficient to recover the used primary reserve capacity and to fully compensate for non-regulated changes in the Electricity System. It is determined as follows:

$$\Delta P^{II}_{r} \geq \sqrt{a \cdot L_{max} + b^2} - b,$$

Where:

L_{max} is the maximum expected consumption peak in the Electricity System during the period observed (MW)
a = 10 MW
b= 150 MW.

    2) The secondary reserve capacity must be ready to be launched in 30 seconds after the onset of an imbalance, reaching its maximum value in 15 minutes without preventing the supply of the primary reserve capacity.
    3) In the event of isolated mode of operation, the ESO shall decide on the requirement for and size of the secondary capacity reserve to be involved. The reserve should be considered only on the hydropower plants without any change in the planned irrigation water flow.
20. The tertiary reserve capacity is intended to operatively fill in within minutes (up to 30 minutes) and then to restore the used secondary reserve capacity, thus ensuring that the Electricity System stands ready to respond to the next loss of generation.

21. The indicators for tertiary reserve are as follows:
    1) The size of the tertiary reserve capacity must be sufficient to recover the used capacity of the secondary reserve.
    2) The tertiary reserve capacity must be ready to be launched within 15 minutes after the onset of the imbalances and reach its maximum value within 30 minutes.
    3) The requirement and size of the tertiary reserve capacity in the event of isolated mode of operation of the Electricity System must be determined by the ESO. The reserve should be considered only on the hydropower plants without any change in the planned irrigation water flow.

CHAPTER 6. RELIABILITY AND SECURITY INDICATORS OF THE ELECTRICITY SYSTEM BY STATIC AND DYNAMIC STABILITY

22. The requirements set for the static and dynamic stability of the Electricity System are as follows:

Characteristics of contingencies	Groups of contingencies	Stability maintained
1	2	3
1) Emergency outage of a network element as a result of unsuccessful action of the ARC, except for: 1. Outage of busbars; 2. Outage of the intersystem connection lines as a result of unsuccessful action of the Single-phase Automatic Recloser (SFARC); 3. Outage of one connection at the cross-section of the Electricity System due to unsuccessful ARC action. 2) Emergency Outage of up to 250 MW generation (installed) capacity.	Group I	I II I
1) Emergency outage of double circuit transit TLs by unsuccessful ARC; 2) Emergency outage of any of the busbars of the distribution facility at a power plant or substation; 3) Contingency shutdown of the reactor unit or of the generation (installed) capacity over 250 MW.	Group II	II
1) Simultaneous outage of two and more independent transit transmission lines by unsuccessful ARC; 2) Emergency outage of two busbars of the distribution facility at a power plant or substation.	Group III	III

23. Point 22 of this Annex in case of the sign "I' maintenance of the given Indicator is mandatory without application of automated measures or interference of the ESO Dispatcher, in case of the sign "II" maintenance of the Indicator is mandatory with application of automated measures or interference of the ESO Dispatcher, and in case of the sign "III" maintenance of the Indicator is not mandatory.

24. At each segment of the Electricity System, the active capacity shall not exceed the maximum permissible active power (Pmax), which should provide for a long-term permissible reserve of static aperiodic stability for not less than 20 percent and short-term (up to 15 minutes) permissible reserve for not less than 8 percent; it should also satisfy the following conditions:

a) in any long-term contingency situation:

$$P_{a.r.} \leq 0.8\, P_{lim}^{st.stability} - \Delta P_{irr.osc.}$$

b) in any short-term Group I N_{k-1} contingency situation:

$$P_{a.r.} \leq 0.92\, P_{lim}^{st.stability} - \Delta P_{irr.osc,}$$

where:

$P_{lim}^{st.stability}$ – static aperiodic stability boundary capacity limit for the given segment.

$\Delta P_{irr.osc.}$ – irregular load flow oscillations caused by oscillations at the generation and consumption sides of a given section.

25. In the case of a Group I N_k-1 contingency situation in the Electricity System, both static and dynamic stability of the system are ensured without the application of special system automation control.
26. In the case of a Group II N_k-1 contingency in the Electricity System, for maintaining static and dynamic stability of the system, application of special system automation control is allowed.
27. In the case of a violation of Electricity System stability (onset of asynchronous state), automated separation of the appropriate segment of the Electricity System should be planned to avoid the development of a cascading fault.
28. The static and dynamic stability of the Electricity System shall be calculated using a verified model. The verification of the model shall be implemented by reproducing several transient processes that actually took place and have been registered in the unified system that monitors transient electromechanical processes in the Electricity System and comparing them with actual changes of calculated operating parameters (capacities, voltages, currents, and frequencies).

CHAPTER 7. RSI OF AUTOMATED REGULATION SYSTEMS

29. The automatic excitation regulators (AER) of generators connected to the Electricity System shall operate under a voltage control regime and have a 4–5 percent regulation imbalance.
30. The primary and secondary regulation of frequency and capacity in the Electricity System shall be implemented in an automated manner, whereas the tertiary regulation shall be implemented in an operative manner (by dispatching), in cases prescribed by the ETN Code.
31. RS Indicators of automated primary and secondary regulation of frequency and capacity in the Electricity System are as follows:

Regulation System	**Type of indicator**	**Value of indicator**
1) Primary	Ranges of frequency regulation	· 50±0.1 Hzt not less than 95 percent of the day · 50±0.2 Hz not less than 98.5 percent of the week · 50±0.4 Hz not more than 15 minutes after the contingency
	Maximum range of frequency dynamic change after Group I contingency	50±0.8 Hz
	Activation (general/normalized)	50±0.15/50±0.1 Hz
	Dead zone (general/normalized)	50±0.075/50±0.05 Hz
	Disparity in regulation	4 percent at thermal plants, 5 percent at nuclear plants, 4–6 percent at hydropower plants
	Speed of response of the reserve capacity	50 percent – not more than 15 seconds 100 percent – not more than 30 seconds
	Total duration of supply of the reserve capacity	Not less than 15 minutes
2) Secondary	Speed of response of the reserve capacity	100 percent – not more than 15 minutes

	Total duration of supply of the reserve capacity	Not less than 30 minutes
	Accuracy of measurement of frequency and capacity	1.5mHz and not more than 2%

CHAPTER 8. ELECTRICITY SYSTEM SECURITY INDICATORS OF SYSTEM AUTOMATION CONTROL

32. The System Automation Control (SAC) of the Electricity System is designed to prevent the occurrence and spread of emergency states and their elimination. The type of impact and values of SAC subsystems, the operational principles and settings of the devices, and their impact on the Electricity System shall be selected in such a way as to ensure coordinated operations of the devices (selective, rapid, sensitive, and reliable).

33. SAC includes the following:
    1) of a Group II contingency in Normal Automated prevention of stability violation (APSV);
    2) Automated elimination of asynchronous mode (AEAM);
    3) Automatic limitation of frequency drop (ALFD);
    4) Protection against frequency increase (PFI);
    5) Special automated load shutdown (SALS);
    6) Voltage down automated limitation (VDAL);
    7) Voltage up automated limitation (VUAL);
    8) Automated separation from frequency drop at power plants (ASFD);
    9) Automated prevention of equipment from impermissible overloading (APEIO).

34. APSV is designed to ensure the dynamic and static stability of the Electricity System in case of a Group II contingency in Normal state of Electricity System operation (allowed for Group III contingencies as well, but not mandatory).

35. APSV must be implemented in those segments of the Electricity System that are risky for stability due to Group II contingencies.

36. Selectivity, sensitivity, and rapidness of the APSV must ensure the stability of the Electricity System, and it must have sufficient impact and be minimal at the same time.

37. Impact modes of APSV on the Electricity System must be chosen from the following list:
    1) Short-term (impulse-induced) or long-term load shedding at thermal power plants, with boilers that are equipped with automatic regulators of steam production;
    2) Generator shutdown;
    3) Disconnection of consumers;
    4) Forcing of the generators' excitation (excitation boost);
    5) Division of the Electricity System into non-synchronous parts.

38. Implementation of AEAM in the Electricity System is mandatory if:
    1) The violation of stability of the Electricity System synchronous operation and occurrence of asynchronous mode jeopardize the security of the system due to the development of a cascading fault and damage to the equipment;
    2) The violation of parts of the Electricity System or any power plant or separate generator synchronous operation, and, consequently, occurrence of asynchronous mode cannot be excluded as a result of sudden or probable occurrence of Group III contingencies of the Electricity System, wrong planning or regulation of operation mode, APSV breach, and other cases.

39. In the Electricity System design and annual dispatch planning processes, the Electricity System stability and asynchronous state calculations (modeling) as well as experience from analysis of previous operation of the grid must be used to determine where the AEAM equipment should be placed at dangerous connections of the sections and lines.

40. Asynchronous mode between the power plant and the Electricity System must be eliminated through automated separation, either as main or reserve operation.

41. AEAM devices must ensure the detection and elimination of both complete and incomplete phase Asynchronous states.
42. To ensure selectiveness of operation of AEAM, principles and settings of devices must exclude the operation of AEAM during the synchronous oscillations and short circuits as well as Asynchronous states that occur outside of the control of the given devices.
43. The settings of AEAM devices must satisfy the sensitivity of AEAM operation in case of an Asynchronous state.
44. Speed of operation of AEAM devices on 400 kV lines and 220 kV connections must prevent transformation of a long-term two-frequency Asynchronous state into a multi-frequency asynchronous state and ensure the security of the equipment.
45. To back up the operation of AEAM devices and switches, at least two AEAM devices must be installed at each section of 110 and 220 kV lines that are at risk of Asynchronous mode occurrence, and on both sides of 400 kV lines.
46. Any Asynchronous state of a generator (toward the power plant) connected to the transmission grid should be eliminated by its automatic shutdown.
47. To ensure the successful separation of the Electricity System in Asynchronous state, AEAM device operation should aim for the location it is placed, i.e., without communicated dispatch instruction. Yet, dispatch instruction for separation in another location by communication is allowed in cases when the backup automated separation was performed on the site.
48. Electricity System separation points should be justified by the result of modeling and operation analysis and should ensure the restoration of the normal operation state of the Electricity System as soon as possible.
49. In the event of active power deficiency (shortage), the ALFD sub-system should ensure the performance of Electricity System security (stability) frequency indicators by eliminating an impermissible frequency drop (decline) and restoration and should include the following operations:
    1) Automated startup and loading by frequency (ASLF);
    2) Automated load shedding by frequency (LSF);
    3) Automated prevention of frequency drop (LSF-1);
    4) Automated restoration of frequency (LSF-2);
    5) Automated load shedding by frequency drop rate (ALSFDR);
    6) Automated reclosing by frequency (ARF);
    7) Electricity System automatic separation from the neighboring system (AS).

50. ASLF should automatically reduce the deficiency of active capacity in case of frequency drop (decline) to reduce or prevent (depending on the magnitude of deficiency) disconnection of consumers due to LSF. ASLF must operate if the frequency declines to 49.4–49.2 Hz.
51. Upon request of the ESO, the ASLF devices must be installed at HPPs with capacity of 20 MW and over.
52. In the event of active capacity deficiency, LSF, by means of preventing an impermissible frequency drop (decline) and restoration, should ensure the security of the Electricity System according to the frequency indicators according to the following principles:

    1) LSF-1 is intended to suspend the frequency drop (decline) to 47.5 Hz in cases when the deficiency of active capacity in the Electricity System does not exceed 45 percent of Electricity System capacity separated from the synchronous zone or maximum load capacity of any of its nodes. The frequency settings of the operation must be implemented within the range of 48.8–47.5Hz with 1 Hz per step and a time delay of 0.1–0.2 seconds, and the capacity of the load to be disconnected by LSF-1 is:

$$\Delta P_{LSF-1} \geq \Delta P_{def.} + 0.05 * P_{load} ,$$

load

where ΔP_{def} is the generated capacity deficiency, P – maximum load in the Electricity System or over any node.

2) LSF-2 is intended to restore the frequency after the LSF-1 down operation;
3) The volume of the LSF-2 must be fully combined with the LSF-1 volume and should operate for the disconnection of the same consumers;
4) The LSF-2 frequency setting must be within the range of 48.8-48.6Hz, with the time set at 4–60 seconds. The step for the time setting is 4 seconds.

53. In case of significant deficiencies (where the active capacity deficiency is over 45 percent), ALSFDR should prevent a severe decline of frequency and accelerate the restoration.
54. The principle of setting the operation of ALSFDR devices must be based on measuring values of frequency and its decline rate and comparing them with the corresponding given settings.
55. Settings of the ALSFDR devices must be regulated:
    1) In the range of 49–49.5 Hz, by frequency;
    2) In the range of 2.0–2.5Hz/sec, by frequency decline rate;
    3) Holding time for 0.1 seconds.
56. Disconnection of a load from the ALSFDR must exclude frequency decline to 47.5 Hz in cases where Electricity System active capacity deficiency exceeds 45 percent of the maximum capacity of consumption.
57. The automated reclosing by frequency (ARF) sub-system should automatically restore electricity supply to consumers disconnected by LSF after frequency restoration.
58. ARF operation settings should be implemented at the 49.5–49.8 Hz range with a time delay of not less than 5 seconds, with a 5-second step set for time.
59. After each sequence of ARF, the connecting load should not cause a double operation of LSF and should not exceed 2 percent of the total load disconnected by LSF.
60. The protection against frequency increase (PFI) sub-system should prevent impermissible increases of frequency in the Electricity System to levels at which security protection of TPPs and nuclear power plant (ANPP) turbines will operate.
61. PFI operation must be performed by frequency within the range of 50.8–51.2 Hz and with a 0.15 second time delay.
62. PFI devices must switch off the generators. Hydro generators must be switched off first.
63. In case of significant loss of generation capacity in the Electricity System, the special automated load shutdown (SALS) devices should prevent:
    1) Disconnection of the interconnection line from the neighboring system;
    2) Impermissible drop of voltage at Electricity System nodes.
64. Voltage down automated limitation (VDAL) should automatically prevent an impermissible drop of voltage, avoiding a violation of stability of the Electricity System node loads by voltage.
65. VDAL devices should control the levels and duration of voltage drops at Electricity System nodes or the rate of voltage drop and/or the reactive capacity.
66. VDAL operation must be implemented by the reactive power compensation or operational modification of the state on the 220 kV or lower-voltage grid and/or by disconnecting consumer load, and on a higher-voltage grid only through reactive power compensation or modification of the operational state.
67. Operation of VDAL devices must be coordinated with the operation of relay protection devices, reserve feeding automatic connection, and automatic reclosing devices.
68. Voltage up automated limitation (VUAL) should prevent impermissible voltage increases (by value and duration) to the equipment.
69. VUAL devices must be placed on each side of 110 kV and higher-voltage lines, the unilateral disconnection of which can cause an impermissible voltage increase to the equipment.

70. VUAL device operating principles must be implemented to control voltage level increases and the duration of each phase as well as values of reactive capacities and direction in the line.
71. VUAL devices' operating settings must ensure the security of the equipment.
72. Operation of VUAL devices must be implemented in two degrees depending on the magnitude of voltage:
    1) First degree with time delay should be aimed at changing the mode of operation of equipment to compensate for reactive power or operational modification of the state;
    2) Second degree should work with a bigger time deay than the first degree and be aimed at two-end disconnection of a line and implementation of three-phase automated reclosing.
73. Automatic separation should ensure the security of the Electricity System by automatically separating from the neighboring system when a severe emergency threatens to violate the following security indicators of the Electricity System:
    1) Electricity System permissible frequency range;
    2) Permissible voltage levels at the nodes of the Transmission network;
    3) Permissible range of load for any element of the Electricity System;
    4) Electricity System stability.
74. The restoration (after separation of the Electricity System from a neighboring system) of the Normal operating state of the Electricity System automatically and/or by instruction of the dispatcher must be carried out in accordance with the program developed and approved beforehand.
75. In case of a frequency drop at Electricity System power plants, the Automated separation from frequency drop (ASFD) at TPPs or a part of those must prevent a shutdown of the plant resulting from the violation of the work of mechanisms for own needs, impermissible vibrations of the turbines, or risk of damage to the blades and base. If the frequency range has dropped to less than 47.5 Hz:
    1) Settings for ASFD device operations at TPPs must be regulated:
        a. First degree: 47.2–47.5Hz / 4–6 seconds;
        b. Second degree: 47.0–47.2Hz / 0.15–0.5 seconds.
    2) Stable operation of a TPP unit for own needs must be ensured for not less than 30 minutes.
76. ASFD devices at HPPs must:
    1) Aim to ensure the restart of disconnected TPP and ANPP generators, to keep running a certain portion of generators with their associated consumers in case of emergencies accompanied by severe loss of capacity in the Electricity System or its nodes, and to separate HPP through the action of ASFD using an estimated balanced load.
    2) Settings for the operation of the ASFD devices placed on the HPP must be regulated:
        a) First degree: 47.2–47.5Hz / 4–6 seconds;
        b) Second degree: 47.0–47.2Hz / 0.15–0.5 seconds.

ANNEX 2. INFORMATION ON AVAILABLE CAPACITIES

_____

(title of the company)

Available Capacities, 20_____

N	Month	1	2	3	4	5	6	7	8	9	10	11	12
	Date	**1-31**	**1-28 1-29**	**1-31**	**1-30**	**1-31**	**1-30**	**1-31**	**1-31**	**1-30**	**1-31**	**1-30**	**1-31**
1.	Rated capacity, including (by facility and equipment):												
1)													
2)													
2.	Planned outage of the capacities, including:												
1)													
2)													
3.	Summary limitation, including:												
1)	Capacity limitations due to climatic conditions												
2)	Limitations due to thermal load												
3)	Limitations due to deterioration of equipment												
4.	Manageable capacity in condensing state, including:												
1)													
2)													
5.	Available capacity in the heating state, including:												
1)													
2)													

1. The columns of the above table can be further broken down by days.

2. Minimal required technical capacity is _____MW (filled out upon necessity).

Representative of the Company _____

Name, Surname
!signature/

ANNEX 3. APPLICATION TO OBTAIN TECHNICAL CONDITIONS FOR CONNECTION TO THE TRANSMISSION NETWORK

1.	**Information about the Applicant**					
1)	Name					
2)	Type of Applicant	Generator				
		Distributor				
		Qualified Customer				
3)	Name of the facility					
4)	Address of the facility					
5)	Surface of the facility to connect according to the cadastre (including the plan)					
6)	Purpose of connection	Connection of new facility				
		Increase of installed capacity				
		Increase of Distributor load				
		Upgrade of the existing facility				
7)	Planned increase (MW) of the upgraded or increased capacity					
8)	Planned level of voltage of the connection point (kV)					
9)	Stages of implementation (yes/no)					
10)	Construction/upgrade period (by stages)	Stage	I	II	III	IV
		Year/month				
		MW				
11)	Address of the Applicant:					
12)	Telephone:					
13)	Fax:					
14)	Responsible person	Name, surname				
		Address				
		Email				
		Telephone				

This part is filled by Generators

2	**Information about generating facility**				
1)	Type of the generating facility	Hydro (run of)			
		Impoundment facility			
		Hydro Reservoir			
		Nuclear			
		Thermal			
		Combined cycle			
		Wind			
		Other (specify)			
2)	Fuel	Coal			
		Gas			
		Oil			
		Nuclear			
		Other (specify)			
3)	Energy data by stage	I	II	III	IV
a.	Number of units				
b.	Active power generation (MW)				
c.	Maximum capacity (MW)				
d.	Annual generation forecast (MWh)				
4)	Capacity to regulate reactive energy (yes/no)				

This part is filled by Qualified Customers and the Distributor

3	**Information about connection facility**				
1)	Type of facility	Industrial			
		Industrial for own purposes			
		Traction			
		General purpose			
		Other (specify)			
2)	Information by stage	I	II	III	IV
a.	Forecast maximum active load (MW)				
b.	Forecast maximum total load (MVA)				
c.	Forecast minimum active load (MW)				

d.	Annual generation (MWh)				
e.	Maximum power generation capacity of its own (MW)				
f.	Annual power generation capacity of its own (MWh)				

Representative of the Company _____

Name, Surname /signature/

ANNEX 4. APPLICATION FOR CONNECTION PERMISSION

1.	Information about Applicant		
1)	Name		
2)	Type of connecting Applicant	Generator	
		Distributor	
		Qualified Customer	
3)	Name of the facility		
4)	Address of the facility		
5)	Surface of the facility to connect according to the cadastre (including the plan)		
6)	Purpose of the connection	Connection of new facility	
		Increase of installed capacity	
		Increase of Distributor load	
		Upgrade of the existing facility	
7)	Term for connection or obtaining the permission for connection		
8)	Construction stages		
9)	Term for completion of the construction (reconstruction)		
10)	Planned capacity of the new or reconstructed connection (MW)		
11)	Planned voltage levels at the point of connection (kV)		
12)	Connection address		
13)	Telephone		
14)	Fax		
15)	Responsible person	Name, Surname	
		Address	
		Email	
		Telephone	

This part is filled in by Generators:

2.	Information about generating facility				
1)	Type of facility	Nuclear			
		Hydro (specify type)			
		Thermal (specify type)			
		Wind			
		Other (specify)			
2)	**Fuel used in thermal and combined cycle facilities**	Coal			
		Gas			
		Oil			
		Other			
3)	**Energy data**	**Existing**		**New**	
a.	Number of boilers				
b.	Number of generators				
c.	Number of step-up transformers				
d.	Overall capacity (MVA)				
e.	Active capacity (MW)				
f.	Reactive capacity (MVAr)				
g.	Maximum active supplied capacity (MW)				
h.	Minimum active supplied capacity (MW)				
i.	Forecast annual production (MWh)				
j.	Nominal voltage of own purposes (kV)				
k.	Maximum active capacity for own purposes (MW)				
l.	Maximum reactive capacity for own purposes (MVAr)				
m.	Capacities to regulate reactive power (yes/no)				
4)	**Information about generator (for each one)**	**1**	**2**	**3**	**4**
a.	Generator model				
b.	Total capacity (MVA)				
c.	Active capacity (MW)				
d.	Power factor (cosϕ)				

e.	Nominal voltage (kV)					
f.	Spinning numbers					
g.	Type of excitation system (spinning/static)					
h.	Type of voltage regulation and system stabilizer					
i.	Short circuit factor					
j.	Synchronous reactive resistance, Xd/ Xq (%)					
k.	Transient reactive resistance, Xd'/Xq' (%)					
l.	Over transient reactive resistance, Xd''/Xq'' (%)					
m.	Time constant, Td/ Tq (sec.)					
n.	Transient time constant, Td'/Tq' (sec)					
o.	Over transient time constant, Td''/Tq'' (sec)					
p.	Generator and turbine inertia torque, GD2 (N*m2)					
5)	**Information about turbines (for each one)**		**1**	**2**	**3**	**4**
a.	Turbine model					
b.	Installed capacity (MW)					
c.	Technical minimum (MW)					
6)	**Information about transformers (for each one)**		**1**	**2**	**3**	**4**
a.	Model of the transformer					
b.	Nominal factor of a transformer (kV/kV)					
c.	Nominal capacities HV/MV/LV (MVA)					
d.	Voltage of short circuit (%)	Usc 1-2				
		Usc 1-3				
		Usc 2-3				
e.	Power of short circuit (kW)	Psc 1-2				
		Psc 1-3				
		Psc 2-3				
f.	Idle power, I (%)					
g.	Loss of idle power, P (kW)					
h.	Voltage regulation (under load, no load)					
i.	Converter range and step (%)					
j.	Connection group					
k.	Positive sequence resistance					
l.	Zero sequence resistance					
m.	Neutral grounding					

This part is filled by the Distributor and Qualified Customers

3.	**Information about connection point**					
1)	Type		Industrial			
			Industrial with own production capacities			
			Traction			
			General			
			Other			
2)	**Energy data**		**Existing**		**New**	
a.	Installed capacity (MW)					
b.	Power factor (cosϕ)					
c.	Anticipated maximum capacity (MW)					
d.	Anticipated minimal capacity (MW)					
e.	Daily graph of anticipated load (daily graph of active and reactive power by winter and summer state (yes/no)					
f.	Load sensitivity over fluctuations of voltage and frequency (describe)					
g.	Maximum level of flickers and harmonic elements that arise due to customer load. Mention specific details related to consumption, such as industrial furnaces or traction stations that can affect the quality of power supplied to other customers.					
h.	Data about regular change of active and reactive power (>5 MVA/minute)					
i.	Gradient of active and reactive power change up/down (>5 MVA/minute)					
j.	Expected annual production volumes of its own (MWh)					
k.	Maximum annual capacity (MW)					
3)	**Information about transformers**		**1**	**2**	**3**	**4**
a.	Model of transformer					
b.	Nominal actor of transformation (kV/kV)					
c.	Nominal capacity HV/MV/LV (MVA)					
d.	Short circuit (%)	Usc 1-2				
		Usc 1-3				
		Usc 2-3				

e.	Short circuit power (kW)	Psc 1-2				
		Psc 1-3				
		Psc 2-3				
f.	Idle power, I (%)					
g.	Loss of idle power, P (kW)					
h.	Voltage regulation (loaded, no load)					
i.	Converter range and step (%)					
j.	Connection group					
k.	Positive sequence resistance					
l.	Zero sequence resistance					
m.	Neutral grounding					

Representative of the Company _____

Name, surname /signature/

ANNEX 5. PROTOCOL (ACT) ON INSTALLING OR CHANGING A METERING COMPLEX OR ITS ELEMENTS

_____

(name of the station, direction of the substation)

Manufacturer's number of the meter (metering transformer) taken out of operation	Type (model)	Reading of the meter		Last calibration date	Nominal power A	Nominal voltage V	Current transformer		Potential transformer	
		From the bus	To the bus				Factor	Accuracy class	Factor	Accuracy class
		Tot.	Tot.							
		T1	T1							
		T2	T2							
Manufacturer's number of the meter (metering transformer) installed	Type (model)	Reading of the meter		Last calibration date	Nominal power A	Nominal voltage V	Current transformer		Potential transformer	
		From the bus	To the bus				Factor	Accuracy class	Factor	Accuracy class
		Tot.	Tot.							
		T1	T1							
		T2	T2							

NOTE _____

"Market Operator" _____ Representative of the Company _____

Name, surname/signature/ Name, surname/signature/

Transmitter/Distributor _____ Representative of the Company _____

Name, surname/signature/ Name, surname/signature/

ANNEX 6. PROTOCOL (ACT) ON SEALING TERMINAL CLAMPS AND/OR INSTALLATION BOXES OF THE COMMERCIAL METERING COMPLEXES

_____

(name of the station, direction of the substation)

N	Seal installation location	DAS Identification number	Number of the removed seal	Number of the seal installed
1				
2				
3				
...				
n				

"Market Operator" _____ Representative of the Company _____

Name, surname/signature/ Name, surname/signature/

Transmitter/Distributor _____ Representative of the Company _____

Name, surname/signature/ Name, surname/signature/

ANNEX 7. PROTOCOL (ACT) ON INSPECTION OF METERING COMPLEXES

_____

(name of the station, direction of the substation)

N	DAS code	Seal installation location	Model of the meter, metering transformer, or elements	Number of the meter, metering transformer, or element	Last calibration	Number of the seal installed	Integrity
1							
2							
3							
...							
n							

NOTE _____

"Market Operator" _____ Representative of the Company _____

Name, surname/signature/ Name, surname/signature/

Transmitter/Distributor _____ Representative of the Company _____

Name, surname/signature/ Name, surname/signature/

ARMENIA ELECTRICITY DISTRIBUTION NETWORK CODE

SECTION 1. GENERAL PROVISIONS AND MAIN DEFINITIONS

CHAPTER 1. GENERAL PROVISIONS AND MAIN DEFINITIONS

1. The Republic of Armenia (RoA) Electricity Distribution Network Code (hereinafter, EDN Code) shall regulate the processes of development planning, distribution network operative management, short-term planning and dispatching of the electricity system, the relationship in the context of connection (change of connection) of consumption systems and new capacities to the distribution network, the requirements for electricity commercial metering systems in the distribution networks, and the procedures to improve the efficiency of distribution network operation.
2. The main definitions used in the EDN Code:

1)	**Fixed Emergency Capacity**	The active capacity stipulated in the Contract with the Customer, which is subject to uninterrupted provision by the Distributor in the Emergency State within the period defined in the Contract to guarantee the operation of electrical equipment responsible for the safety and security of human life and the environment.
2)	**Fixed Technological Capacity**	The active capacity stipulated in the Contract with the Customer, which is subject to uninterrupted provision by the Distributor within the period defined in the Contract in order to bring to an end the treatment of raw material during the production process, or to withdraw the raw material from the production process without any waste or damage to the production equipment.
3)	**Commercial Metering Device**	A metering device for commercial measurement of electricity specified in the Contract with the Customer or in the Registration Card.
4)	**Generator**	An entity eligible for generation of electricity (capacity).
5)	**Generator Connection Fee**	An amount charged in compliance with the EDN Code for connection of the Generator.
6)	**Generator Connection**	Connection to or change of connection of Generator's power plant (capacities) to the Distribution Network.
7)	**Distribution Network**	A unified system of electricity distribution lines, substations, and other facilities under the control and operation of the Distributor.
8)	**Distributor**	An entity holding a license for provision of electricity distribution services.
9)	**Applicant**	An entity, including a Customer, applying for connection. In case of connection of a newly constructed multi-apartment building or a district under construction, the Developer is considered to be an Applicant.
10)	**ETN Code**	The RoA Electricity Transmission Network Code approved by the Commission.
11)	**Autonomous Power Producer (APP)**	A legal or physical entity generating electricity for own needs and possessing energy facilities with installed capacity not exceeding the overall installed capacity of its electricity consumption devices, but not more than capacity stated in the Law.

12)	**Autonomous Power Producer Connection**	Connection or change of connection of the APP's power plant (capacities) to the Distribution Network.
13)	**Large Customer**	A customer of 5 MW or more capacity connected to the Distribution Network.
14)	**Dispatch**	A set of processes and actions required for technological management of the power system aimed at declaration and planning of electricity generation, import, export, transit opportunities, and consumption forecast and aimed to cover the entire electricity demand in real-time mode, ensuring provision of electricity supply of the defined quality and maintaining reliability and safety indicators of the electricity system.
15)	**Transmitter**	An entity holding a license for electricity (capacity) transmission.
16)	**System Operator**	An entity holding a license for provision of Electricity System Operator services.
17)	**Commission**	The Public Services Regulatory Commission of the RoA.
18)	**Metering Point**	A Boundary point or a point of the electric network close to the Boundary point where the Commercial metering device or Control metering device is installed.
19)	**Registration Card**	Individual registration card of the Customer opened by the Distributor pursuant to the Retail Electricity Market (REM) Rules, containing Customer identification data and information as defined in the REM Rules and EDN Code.
20)	**Metering device**	A set of combined devices envisaged for measurement and settlement of electricity (capacity), including an electricity meter or a set of measuring current and voltage transformers and electricity meters calibrated by a metrological body, and, if available, impulse sensors, modems, adders, connection wires, and uninterruptible electricity feeding devices ensuring autonomous reliable feeding for at least 1.5 hours.
21)	**Supplier**	An entity holding the license for electricity supply.
22)	**Connection Point**	A physical point of the Distribution Network to which a power plant of a Generator and/or a consumption system of an Applicant is connected.
23)	**Market Participants**	Generator, Distributor, Transmitter, Electricity System Operator, Electricity Market Operator, and Customers.
24)	**Market Operator**	An entity holding a license for provision of power market operation services.
25)	**Contract**	A contract developed in the model form approved by the Commission on connection of the consumption system to the electric network, distribution of electricity, and universal supply of electricity, and/or a contract on connection of a consumption system of a multi-apartment building under construction or a developing district to the electricity network.
26)	**Qualified Customer**	A customer having been recognized by the Electricity Market Operator as Qualified based on compliance with the criteria defined in the RoA Wholesale Electricity Market Trading Rules approved by the Commission.

27)	**Boundary Point**	Balance ownership border of the electric facilities.
28)	**Consumption System**	A group of electric facilities of the Customer.
29)	**Connection of the Consumption System (Connection)**	New connection or change of the existing connection of the Customer's Consumption System to the Distribution Network.
30)	**Customer**	An entity demanding electricity, who has signed or is in the process of signing an electricity supply contract with the Electricity Supply Licensee (including Universal Supplier).
31)	**Customer Connection Fee (Connection fee)**	An amount charged to the Applicant for connection of a Consumption System.
32)	**Control Metering Device**	A meter specified in the Contract or in the Registration Card to Control the measurement of electricity.
33)	**Technical Conditions**	Specifications for connection to the Distribution Network at least cost, which are necessary to ensure the connection of electric facilities at technical parameters specified in the connection application, and metering of electricity.
34)	**Reference**	A document on the feasibility of connecting to the Distribution Network provided to the entity intending to obtain a license for electricity (capacity) generation.
35)	**Distribution-Scale Plant**	A power plant with up to 10 MW installed capacity, connected to the Distribution Network, except for APPs.
36)	**Simplified Network Connection**	Connection of a new or reconstructed Consumption System of the Customer or New Customer to a 0.22 kV and 0.4 kV Distribution Network with a capacity of up to 30 kVA when a standard connection fee is defined for such connection and no land works are required.

3. The main definitions used in the EDN Code shall have the meanings defined by the Energy Law, ETN Code, and REM Rules, unless otherwise specifically provided for by the EDN Code.

CHAPTER 2. THE OBJECTIVES OF THE EDN CODE

4. The objectives of the EDN Code are as follows:
   1) Regulate the development planning and normal operation of the Distribution Network;
   2) Regulate the technical nature of relations between Market Participants operating in the Electricity System and define their rights and responsibilities;
   3) Ensure open, transparent, and non-discriminatory access to and use of the Distribution Network.

CHAPTER 3. INFORMATION SUBMISSION AND NOTIFICATION

5. The exchange of information among the Market Participants and submission of documents shall be performed in a proper way.
6. The exchange of information and submission of documents shall be deemed appropriately performed if they have been delivered personally with a mail delivery confirmation, or through the document sharing platform (if such is available for the recipient of that correspondence), or by a registered letter (including with a notice of delivery), by email (including the email address specified by the Customer), or other means securing the integrity of the message (including sending a message to a phone number specified by the Customer), which allow confirmation of receipt of the correspondence or, in certain cases defined in the Law, confirmation of the fact of being properly notified, unless other methods of notification or document submission are specifically mentioned in the EDN Code.
7. The Customer shall be required to immediately inform the Distributor about any change of data regarding its address, email, or other means of communication. If such a notice is not sent, the information and the documents shall be provided to the recipient's last known address and the recipient shall bear all the risks associated with the adverse consequences of not providing the information.
8. If the recipient refuses to receive the correspondence or to sign the mail delivery confirmation, if sent via postal delivery, or for some reason the documentation sent by a registered letter is returned, the documentation shall be deemed appropriately delivered to the recipient by the sender on the 3rd day starting the next day that the documentation is available on the Distributor's official website and on http://www.azdarar.am and the latest announcement on the opportunity for the recipient to become aware of the content thereof is published.
9. The Distributor shall provide a written answer to the written application of the Customer or Applicant and a verbal answer to the verbal application, or shall respond via email, if the application has been submitted via email, within 10 business days after the receipt of the application (except for verbal applications). The answer to a verbal inquiry shall be provided verbally immediately after the inquiry is received or in the shortest possible time.
10. The Market Participant shall be liable for the accuracy of information provided.
11. Where inaccuracies are revealed in the information provided by a Market Participant, those should be corrected within 3 business days after the inaccuracies are revealed and the parties notify each other, unless another term is specified in the EDN Code.
12. Information (documents) shared among Market Participants, as well as those submitted to the Commission, shall be in the public domain if not deemed confidential in accordance with the Law.
13. Data (documents) specified in Provision 12 of the EDN Code may be published in procedures defined by the Law. The party that published such information or documents shall bear responsibility for violating legislative requirements regarding the confidentiality of such information (documents).
14. Any data or document provided in the context of the EDN Code shall be preserved for at least a 5-year period, unless a longer term is specified in the EDN Code for storage of such type of documentation.

15. It is prohibited to request that the Applicant make payments or compensation or provide information and documents; it is also prohibited to overburden the latter with obligations that are not covered by the EDN Code, Contract, and other normative legal acts.

CHAPTER 4. MARKET PARTICIPANTS' RESPONSIBILITIES, DISPUTE (DISAGREEMENT) RESOLUTION

16. For non-compliance or inadequate compliance with Provisions of the EDN Code, Market Participants shall bear responsibility in procedures defined by the Law and EDN Code.
17. Market Participants shall not be responsible for violations defined in the EDN Code, if they happened due to force majeure circumstances.
18. In terms of the EDN Code, any circumstance or event (or after-effect of that event) that led (or is leading) to non-fulfillment or inadequate fulfillment of obligations defined by the EDN Code and at the same time is characterized by features stated below, is considered a force majeure situation:
    1) Is out of the control of the party affected by a force majeure situation;
    2) The affected party undertook all possible actions and efforts (including precautional, alternative, legally defined) to prevent, weaken, eliminate, or avoid the influence of those circumstances (after-effects).
19. In terms of the EDN Code, the following situations in particular are considered force majeure cases:
    1) Natural and man-made calamities; epidemics; acts of God (including floods, earthquakes, hurricanes, tornados, thunderstorms, heavy rains with lightning, snowstorms and landslides); nuclear, chemical, or biological contamination; strikes; and public disorders;
    2) Rebellions, terroristic acts, wars, invasions, armed conflict, actions of foreign enemies, and blockades that take place on or involve the territory of the RoA and could not reasonably be predicted.
    3) An act, activity, or inactivity of a state, municipal agency, or other authorized body, due to which no permission or right was issued or extended to facilitate fulfillment of obligations, or due to which fulfillment of such obligations was hindered, on condition that the affected party acted in compliance with the RoA legislation.
20. If a force majeure situation occurs, the affected party shall notify the other party about such circumstances within 10 days after being informed or after being impacted by those circumstances. The party that failed to notify the other party shall bear the risks associated with negative impacts of non-notification.
21. Provision 19 of the EDN Code shall not restrict the Market Participant's right to apply to the Commission if extraordinary and unavoidable circumstances other than those described above occur, requesting that the Commission recognize them as force majeure circumstances as well, on condition that they satisfy the requirements of this Chapter.
22. Where a dispute (disagreement) arises between WEM Participants, the parties shall resolve them through negotiations.
23. If a dispute (disagreement) is not settled by the parties, any party may apply to the Commission requesting that it resolve the dispute within its jurisdiction, as well as may file a suit at a competent court, unless the parties have agreed to submit their dispute to arbitration.

SECTION 2. DISTRIBUTION NETWORK DEVELOPMENT PLANNING

CHAPTER 5. GENERAL PROVISIONS

24. The purpose of Distribution Network development planning (hereinafter, Development planning) is to enable the development of the Distribution Network at the economically justified lowest cost on the condition that the reliability and safety of electricty system operation are secured.
25. Development planning shall be based on the Energy Law of the RoA (hereinafter, the Law), this Section, the requirements of the Electricity Market Transmission Network Code, and technical regulations.
26. Development planning shall aim to solve one or several of the following issues in the Distribution Network:
    1) Generation capacity increase based on the forecasted increase in volumes of Applicants' consumption system connections and increase in consumption demand;
    2) Improvement of Customers' service quality indicators;
    3) Ensuring electricity quality indicators;
    4) Reduction of losses or consumption of electricity for own needs;
    5) Replacement of obsolete assets or assets subject to write-off with new ones;
    6) Improvement in the level of safety and reliability;
    7) Implementation of environmental protection measures;
    8) Implementation of energy-saving measures;
    9) Introduction of efficient modern technologies;
    10) Integration of facilities that use renewable energy resources;
    11) Compliance with Energy Sector development strategies as well as requirements of legal acts of the Commission and other competent authorities;
    12) Compliance with the requirements of the TYNDP approved by the ESO;
    13) Implementation of all actions pertaining to the given licensee for a corresponding period under a General Long-Term Electricity System Development Plan approved by the ESO;
    14) Implementation of other necessary actions for improving the efficiency of licensed activities.
27. The Development planning process shall be carried out in the following stages:
    1) Collecting and processing of information;
    2) Performing necessary studies;
    3) Modeling;
    4) Drafting and approval of the Development plan.
28. Every other year, the Distributor shall prepare the Development plan, considering therein the development of the Distribution Network for the next 10-year period.
29. Actions indicated in the Development plan shall be included in the Distributor's investment plans.
30. The Distributor may engage independent experts or firms for the drafting of the Development plan.
31. For the activities indicated in the Development Plan, the timeframes for construction and reconstruction works on facilities shall be estimated, including those for project planning, design, and state and municipal government, as well as for receiving authorizations from regulatory bodies and for construction.

CHAPTER 6. DEVELOPMENT PLANNING CRITERIA

32. The development planning process shall consider the expected changes in electricity consumption, production volumes and structure of Distribution-Scale Plants and scenarios thereof, opportunities for the use of new technologies, and other possible developments.

33. The planning process shall include estimates of Distribution Network operating regimes by season (winter, spring, summer, and autumn).
34. Potential risks of disruption to the normal operation of the Distribution Network shall be assessed during the planning process and recommendations on reducing the negative consequences of their impacts shall be developed.
35. The Development planning shall be done in such a manner that:
    1) All performance indicators of electrical equipment and facilities under the operational control of the Distributor under normal conditions of the power system are within the range defined for such equipment by the manufacturers, and the quality of power supplied by the distribution network complies with the requirements of technical regulations;
    2) The level and duration of overloading of electrical equipment and facilities under the operational control of the Distributor comply with the indicators defined by their manufacturers and existing technical requirements, considering external factors;
    3) The power factor (cos ϕ) at the Customer's Boundary point (excluding residential Customers) is within the range of 0.9–1.0 95 percent of the time;
    4) Disconnection of one power unit (transformer, switch, etc.) at substations with two 35–110 kV transformers does not lead to 30 percent or higher loss of the substation load;
    5) Deviations of voltage are maintained at the target levels set by the Commission;
    6) Electricity supply interruption indices (System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)) are maintained at target levels set by the Commission.

CHAPTER 7. INFORMATION COLLECTION AND PROCESSING

36. The Distributor shall collect, process, and summarize the information and data necessary for planning purposes.
37. The Distributor shall develop the data submission forms to be provided by Distribution-Scale Plants and Large Customers for planning purposes.
38. For the planning process the Distributor may request data and information from Large Customers and Distribution-Scale Plants to be submitted within 20 business days after receiving the request.
39. In case of intention to take installations that are elements of the Distribution Network out of operation, the Large Customers and Distribution-Scale Plants shall inform the Distributor at least 1 year before the planned decommissioning.
40. The Distributor may request that Distribution-Scale Plants and Large Customers submit additional information to check the accuracy of the planning information, to be provided within 10 days after receiving the request.
41. If the Distribution-Scale Plants and Large Customers reveal inaccuracies in the information they provided in the development plan, they shall inform the Distributor in writing within 3 business days after the inaccuracy is revealed.

CHAPTER 8. STUDIES REQUIRED FOR PLANNING AND MODELING

42. Distribution Network Development planning shall be implemented based on the following studies:
    1) Assessment of electricity demand for active and reactive power;
    2) Assessment of operating regimes of the Distribution Network;
    3) Assessment of the impact on the Distribution Network of connecting new consumption systems or Distribution-Scale Plants to the Distribution Network;
    4) Assessment of projected changes to electricity and capacity demand and impacts, the

time when new installations are ready for operation, and actions necessary for correcting deficiencies in existing installations,

5) Load flow, short circuit, Distribution Network stability and voltage level studies at checkpoints, as well as voltage level studies at the Boundary points with the Customers;
6) Assessment of Distribution Network behavior under Normal and Emergency regimes;
7) Study of possible congestion in the Distribution Network elements;
8) Assessment of the behavior of the Distribution Network during deviations or mutual disconnections;
9) Any other study or assessment that may be required to guarantee the reliable and secure operation of the Distribution Network at the economically justified lowest cost in the future.

43. Development planning of the Distribution Network within the framework of the Development Plan shall be performed through modeling. The impact of real objects, processes, and phenomena shall be modeled.

44. The following key assumptions shall be considered while modeling Distribution Network development:
1) Electricity and capacity demand shall be represented at peak, off-peak, and minimum load conditions;
2) Electricity and capacity demand shall be modeled for the forecasted regimes of the Customers,
3) Scheduled removal of distribution network facilities from service for repair, as well as other restrictions needed for regime adjustments, shall be taken into account;
4) Distribution Network facilities shall be modeled to consider their scheduled removal from service stipulated by technical maintenance and construction, as well as long-term forced outages;
5) Inter-system flows shall be modeled to examine their impact on the power system;
6) Relay Protection and automation parameters shall be modeled for necessary adjustments.

45. The development shall be modeled for the main and alternative scenarios, both optimistic and pessimistic scenarios.

46. Distribution Network profiles during modeling shall meet the power sector safety and reliability indicators.

47. The modeling software used for development planning shall guarantee reproduction of real-time processes.

CHAPTER 9. DEVELOPMENT AND APPROVAL OF THE DEVELOPMENT PLAN

48. The development plan shall be developed and approved by the Distributor in cooperation with Distribution-Scale Plants, Large Customers, and the ESO.

49. The development plan shall present the results of all studies pursuant to the requirements of the EDN Code and summarize the measures envisaged to ensure the further reliable and safe operation of the Distribution Network at the economically justified least cost for each of the 10 years of the planning period, according to the following sections:
1) Forecast of electricity and capacity demand in the distribution network;
2) Forecasts of electricity generation at plants connected to the distribution network as well as descriptions of and preferable connection nodes for new generation capacities planned;
3) Information on infrastructure to be built in the distribution network over the next 10 years;
4) Information on new or reconstructed facilities to be connected to the distribution network (on connection applications and other information received by the Distributor);
5) Information on consumption systems;
6) Information on the capacity of each node of the Distribution Network and on the need to strengthen the given node for integration of new loads and facilities into the Distribution Network;
7) Information on existing problems and appropriate plans to address problems related to service quality and compensation of reactive power and electricity losses;
8) Description of Distribution Network development measures,
9) Efficiency analysis for expenses (including technical and economic indicators).

50. Once it finishes collecting, processing, and summarizing data and information as prescribed by Chapter 8 of the EDN Code, the Distributor shall publish the draft development plan on its official website and notify the ESO, Distribution-Scale Plants, and Large Customers by October 15.
51. Upon receipt of the notification mentioned in Provision 50 of the EDN Code, the ESO, Distribution-Scale Plants, and Large Customers shall provide to the Distributor their recommendations and opinions on the draft development plan within 20 business days.
52. Within 20 business days after the receipt of recommendations and opinions on the draft development plan, the Distributor shall summarize them and notify the Commission thereon.
53. After 40 business days from the receipt of the Distributor's notification, the Commission shall provide its opinion and recommendations on the revised draft development plan to the Distributor, as provided for in Provision 52 of the EDN Code.
54. Within 20 business days after the receipt of recommendations and opinions on the draft development plan, the Distributor shall summarize them and approve the Development Plan.
55. Within 5 business days, the Distributor shall submit the approved Development Plan to the Commission and publish it on its official website.

SECTION 3. SHORT-TERM PLANNING

CHAPTER 10. GENERAL PROVISIONS

56. The purpose of short-term planning of the Distribution Network is to schedule the reliable and safe performance of the Distribution Network on a yearly basis, ensuring compliance with the requirements of the ESO for planning of the reliable and secure operation of the Electricity System.
57. The following actions shall be considered during short-term planning:
    1) Annual schedule of planned outages at the Distribution Network (DNOP);
    2) Annual forecasted electricity demand of Customers connected to the Distribution Network (DNDF);
    3) Annual generation structure forecast for the Distribution-Scale Plants (DGEN);
    4) Annual forecast of Distribution Network losses and own needs for the Distribution Network (DLOS).
58. The data and information necessary for short-term planning shall be collected, processed, and summarized by the Distributor. For short-term planning, the Distributor shall establish the list and submission forms of data and information to be submitted by the relevant Market Participants in accordance with the requirements of this Chapter.
59. The Distributor may request additional information or clarifications from Market Participants during short-term planning. Market Participants shall provide additional clarifications to the Distributor in accordance with the procedures and in terms set forth in Chapter 3 of the EDN Rules, unless another, longer term is defined by the parties.

CHAPTER 11. PLANNING FOR OUTAGES OF EQUIPMENT AND DEVICES

60. The Distributor shall develop the DNOP based on the information on planned outages received from Distribution-Scale Plants and Large Customers (hereinafter, Distribution Outage Plan Participants—DOPPs).
61. The Distributor shall compile the DNOP on an annual basis and shall adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
62. The DOPPs shall provide the information on annual outages of their facilities for the following year to the Distributor by May 15 of the given year, whereas the monthly and daily adjustments for annual information shall be provided as follows:
    1) By the 7th of every month for the following month;
    2) Each business day by 09:30 for the following second business day, and if the following days are non-business days, for those days and for the next business day as well.
63. The DOPPs' information on annual, monthly, and daily planned outages of their electric facilities submitted to the Distributor shall include at least the following:
    1) Description of the electric facility subject to the planned outage;
    2) Duration of the planned outage;
    3) Planned outage start and end dates;
    4) Justification for the planned outage.
64. The Distributor shall compile and adjust the DNOP based on the information submitted by the DOPPs as prescribed in Provision 60 of the EDN Code.
65. The Distributor, while compiling the DNOP, shall maintain the schedules for planned outages suggested by the DOPPs, unless those negatively affect the reliability and security indicators of the Distribution Network.
66. The Distributor shall submit the DNOP each year by June 1 to the DOPPs for review.

67. Upon receipt of the DNOP, the DOPPs shall provide their suggestions and comments to the Distributor by June 10.
68. The Distributor shall summarize the suggestions and comments received from the DOPPs, and by June 15 of the current year, shall submit to the ESO its own data for the development of EPOS in procedures defined by the ETN Code, while in parallel, notifying the DOPPs regarding the submission.
69. After the ESO publishes the annual schedule of planned repairs of the Electricity System in procedures defined by the ETN Code, the Distributor shall send the final version of the DNOP to the DOPPs by September 5. The monthly and daily adjustments to the DNOP shall be provided to the DOPPs by the Distributor in the following timeframes:
    1) By the 27th of every month for the following month;
    2) Each business day by 13:00 for the following second day, and if the following days are non-business days, for those days and for the next business day as well.

CHAPTER 12. DEMAND FORECAST

70. The Distributor shall compile the DNDF based on the demand forecast data provided by Large Customers and the results of its own electricity demand analysis.
71. The Distributor shall compile the DNDF on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
72. The Large Customers shall submit their demand forecasts to the Distributor each year for the following year by September 1 and the adjusted monthly and daily forecasts of the annual demand within the periods defined in sub-Provisions 1 and 2 of Provision 59 of the EDN Code, respectively.
73. Annual demand forecast submitted by Large Customers to the Distributor shall include:
    1) The annual demand forecast of electricity by month (MWh);
    2) The minimum and maximum active capacity demand by month (MW);
    3) The minimum and maximum reactive capacity demand by month (MVAr);
    4) The hourly load schedules for:
        a. Business days;
        b. Saturdays and Sundays;
        c. Public holidays and commemoration days.
    5) Demand-side management measures, if envisaged.
74. The monthly demand forecast submitted by Large Customers to the Distributor shall include:
    1) The monthly demand forecast of electricity by day (MWh);
    2) The minimum and maximum active capacity demand by day of the given month (MW);
    3) The minimum and maximum reactive capacity demand by day of the given month (MVAr);
    4) The adjusted hourly load schedules for the given month in the format provided in Provision 70, sub-Provision 4 above;
    5) The adjustments to demand-side management measures for the given month, if envisaged.
75. The daily demand forecast submitted by Large Customers to the Distributor shall include:
    1) The hourly distribution of daily electricity demand (MWh);
    2) The hourly distribution of daily reactive capacity demand (MVAr).
76. The annual, monthly, and daily demand forecasts shall be submitted by Large Customers to the Distributor for all Distribution Network connection points and shall take into account any anticipated changes during the planning period.
77. The Distributor shall compile the annual DNDF based on data provided by Large Customers according to Provision 70 and according to Provisions 74 and 75 of the EDN Code for the monthly and daily adjustments, respectively; it shall also consider the following:
    1) Expected GDP growth in the country;
    2) Potential impact of energy efficiency projects;

3) Historical demand data;
4) Forecast of Distribution Network losses;
5) Possible impact of weather forecasts;
6) Other information and factors that may have an impact on the distribution demand forecast.

78. The Distributor shall compile the DNDF for the next year by October 1 of the given year, and the adjusted monthly and daily forecasts within the periods defined in Provision 62, sub-Provisions 1 and 2 of the EDN Code, respectively.
79. The Distributor, based on the DNDF and DNLF, shall submit to the ESO its own data for the development of the EDEM according to procedures defined in the ETN Code.

CHAPTER 13. GENERATION STRUCTURE FORECAST

80. The DGEN shall be compiled by the Distributor based on the data provided by the Distribution-Scale Plants and the results of the Distributor's analysis.
81. The Distributor shall compile the DGEN on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
82. The Distribution-Scale Plants shall provide to the Distributor the hourly generation schedules forecasted for the following year for each generating unit by September 1 of each year, as well as:
    1) Each generating unit's maximum available capacity on a weekly basis;
    2) Delivery of electricity at each Connection point with the Distribution Network.
83. The Distribution-Scale Plants shall adjust and submit to the Distributor the information provided in Provision 82 of the EDN Code, within the periods specified in Provision 62, sub-Provisions 1 and 2 of the EDN Code, respectively.
84. The Distributor shall compile the DGEN based on the data submitted by Distribution-Scale Plants in accordance with Provision 82 of the EDN Code while considering the following as well:
    1) The need for efficient use of the installed capacities of these generators and historical data of generation volumes;
    2) Power purchase guarantees given to these generators;
    3) Entry of new generation capacities into the Distribution Network and retirement of current generation capacities;
    4) Possible impact of weather forecasts;
    5) Possible impact of energy efficiency projects;
    6) Other information and factors that may have an impact on the DGEN.
85. The Distributor shall compile the DGEN for the next year by October 1 of the given year, and the adjusted monthly and daily forecasts within the periods defined in Provision 62, sub-Provisions 1 and 2 of the EDN Code, respectively.
86. The Distributor, based on the DGEN, shall submit to the ESO its own data for the development of the EGEN in procedures defined by the ETN Code.

CHAPTER 14. DISTRIBUTION NETWORK LOSS FORECAST

87. The Distributor shall calculate the DLOS as the total sum of losses of Distribution Network facilities.
88. The Distributor shall develop the DLOS forecast on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
89. The Distributor shall calculate the DLOS forecast based on the following:
    1) DNOP;
    2) DGEN;
    3) Weather conditions;
    4) Distribution Network topology.

90. The Distributor shall present in the DLOS the losses and own needs of the Distribution Network for the next year on an hourly basis.

91. The Distributor shall develop the DLOS for the next year by October 1 of the given year, and the adjusted monthly and daily forecasts within the periods defined in Provision 62, sub-Provisions 1 and 2 of the EDN Code, respectively.

SECTION 4. OPERATIVE MANAGEMENT OF THE DISTRIBUTION NETWORK

CHAPTER 15. GENERAL PROVISIONS

92. This section shall regulate the activities between the Distributor and entities specified in this Chapter in order to ensure the reliable and secure operation of the Distribution Network.
93. The Distributor and the following entities shall participate in the operative management (hereinafter, the DOMPs):
    1) Transmitter;
    2) Generators;
    3) Customers that are required to have operative personnel (responsible for electric facilities) as prescribed by the technical regulation approved by the RoA Government (hereinafter, the DOM customers).

CHAPTER 16. OPERATIVE SUBORDINATION

94. In terms of operative subordination, equipment and RPA devices of the DOMPs may be placed:
    1) Under the proceeding of the ESO's Dispatcher and the management of the Distributor's Dispatcher;
    2) Under the operative management and proceeding of the Distributor's Dispatcher;
    3) Under the operative proceeding of the Distributor's Dispatcher and the operative management of the DOMP.
95. The list of equipment and RPA devices of the DOMPs to be handed over to the operative subordination of the Distributor shall be defined by the Distributor, and the formalities in this regard shall be completed by December 1 of the given yearbased on the written consent of the DOMP provided to the Distributor. If no changes occur in the agreed list of equipment and RPA devices for the previous year, then the list shall remain effective for the next year as well. Further changes in the equipment and RPA devices shall be done as necessary, based on data provided by the DOMP or initiated by the Distributor.
96. The list shall include those equipment and RPA devices of the DOMP that were not included in the list defined by the ESO, and the dispatch whereof by the Distributor is essential to fulfill the functions stipulated by its operational license;
97. The operative personnel of the DOMP shall carry out operations with equipment and RPA devices under the operative management of the Distributor's Dispatcher following the orders of the Distributor's Dispatcher. The latter shall give a separate order for each operation.
98. Operations with equipment and RPA devices under the operative proceeding of the Distributor's Dispatcher and at the same time under the operative management of the DOMP shall be carried out by the operative personnel of the latter upon the permission of the Distributor's Dispatcher.
99. The operative personnel of the DOMP shall be required to immediately inform the Distributor's Dispatcher about all failures and impermissible deviations from the regime parameters of the equipment and devices that are under operative subordination of the latter.
100. The operative personnel of the DOMP that report to the Distributor's Dispatcher shall be obliged to report to the Distributor after accepting the shift, as well as at the latter's request to report at any time on the current scheme, the state of the equipment and devices under the operative subordination of the Distributor's Dispatcher, the regime parameters, the existing defects, the planned repairs, and replacements.

CHAPTER 17. CONDUCTING OPERATIVE COMMUNICATIONS

101. Each year before December 1, the Distributor and the DOMPs shall be obliged to present to each other the following documents approved by their authorized persons:
    1) The list of employees entitled to conduct operative communications;
    2) The list of operative personnel entitled to conduct operative communications and switches.
102. Operative communications shall include:
    1) Orders from the Distributor's Dispatcher to the DOMP's operative personnel and reporting on their execution by the latter;
    2) Messages from the DOMP's operative personnel on equipment status changes, violations, and regime parameters.

CHAPTER 18. DISPATCH ORDERS

103. The Distributor's Dispatcher shall be entitled to issue the following orders regarding the equipment and RPA devices under its operative subordination:
    1) Disconnect, connect, or energize the electric facilities;
    2) Organize unscheduled visits to the overhead line sites;
    3) Purchase equipment and devices.
104. The Dispatch order shall define the activity to be carried out and the period for its implementation. The Dispatch orders shall be made clear to avoid miscommunication and error probability to the greatest extent possible.
105. Once an order from the Distributor's Dispatcher is received, the DOMP's officer on duty shall repeat it and obtain confirmation. Each order from the Distributor's Dispatcher and a corresponding record of the DOMP's officer on duty regarding its execution shall be made in the operative logs of the Dispatcher and the given DOMP. A Dispatch order shall be executed unconditionally starting at the moment of its approval by the ESO's Dispatcher.
106. Where the DOMP's officer on duty considers that the issued Dispatch order does not comply with the EDN Code requirements, it should immediately inform the Distributor's Dispatcher about this and provide its arguments. If the Dispatch order issued by the Distributor's Dispatcher receives approval, the DOMP officer on duty shall unconditionally execute the order, making a corresponding record in the operative log. Where the implementation of the Distributor's Dispatch order issued by the Distributor is impossible, the DOMP shall immediately inform the Distributor.
107. If the operative duty of the DOMP is carried out by one officer, then that officer must obtain permission from the Distributor's Dispatcher to leave his/her workplace.
108. The Distributor shall ensure the automatic recording and electronic archiving of all dispatch (operative) conversations between the DOMPs and him or herself. Orders sent to the archive shall be kept for at least 3 years. The information may be provided to the DOMPs upon a written request by the latter within 7 days after receiving the request.
109. In case of loss of communication and impossibility of issuing (or receiving) Dispatch orders:
    1) The Distributor and DOMPs shall take necessary actions to restore communication;
    2) The Distributor and DOMPs shall organize new communication channels and inform each other.

CHAPTER 19. DISPATCHING OF RELAY PROTECTION AND AUTOMATION DEVICES

110. Each year by November 1, each DOMPs shall submit for the approval of the Distributor a notification of the next year's schedule of planned inspections and settings of the RPA devices under the latter's operative subordination.
111. Each year by December 1, the Distributor shall submit to the DOMPs:
    1) The settings of the RPA devices agreed by the Distributor,

2) Tasks regarding the changes of settings or new settings of RPA devices and the deadlines for implementation thereof;
3) Agreed schedules of planned inspections of RPA devices.

112. The Distributor shall calculate the settings of RPA devices, recommend such to the DOMPs, and monitor the implementation thereof.
113. If they receive an instruction from the Distributor to change the setting of the RPA devices, the DOMPs shall be required to execute the instructions within the set time and immediately inform the Distributor upon execution.
114. In case of emergency disconnections, the DOMPs shall be required to do the following upon request of the Distributor:
    1) Within 2 days, provide information about the place and the type of the short circuit that occurred in their area, as well as information received from the accident recording devices;
    2) In the case of a malfunction of the RPA devices, perform post-emergency inspections and share the findings with the Distributor in written form.
115. The DOMPs shall be obliged to:
    1) Eliminate any malfunctions of the RPA devices as soon as possible and duly inform the Distributor;
    2) Carry out an unscheduled inspection of the RPA devices at the Distributor's justified request;
    3) Inform the Distributor about the results immediately after carrying out scheduled and unscheduled inspections.

CHAPTER 20. WITHDRAWAL OF EQUIPMENT AND RPA DEVICES FROM OPERATION

116. Planned repairs of equipment and RPA devices operating under the operative subordination of the Distributor's Dispatcher shall be performed in accordance with the applications submitted by DOMPs. The applications shall indicate the dispatch name of the equipment or RPA device, the content and duration of works, and the dates of taking the equipment or RPA device out of service for repair (emergency readiness) and putting it back into operation, if necessary.
117. Applications for planned repairs shall be submitted to the Distributor's operator 2 days prior to the day of repair within the period from 11:00 to 14:00.
118. Applications to extend the term of repair shall be reported 1 day before their deadline expires. The reason for the extension and deadline shall be indicated in the Application.
119. The Distributor's Dispatcher shall respond to Applications shortly before the scheduled repair.
120. Before starting works required by the Application, the DOMP's operative personnel shall be required to obtain a permit from the Distributor's Dispatcher to put the equipment into repair.
121. In case of failure to perform the work authorized by the Application, the Distributor's Dispatcher shall indicate the reason for its failure, making a relevant record about it in the operative log.

CHAPTER 21. INTERRUPTION AND RESTORATION OF ELECTRICITY SUPPLY FROM DISTRIBUTION-SCALE PLANTS

122. The Distributor may interrupt the electricity supply from Distribution-Scale Plants to the Distribution Network due to planned and unplanned outages in the Distribution Network.
123. The Distributor shall be required to inform the Distribution-Scale Plants of the dates of planned interruptions and restorations of electricity supply at least 2 business days prior.
124. The Distributor shall carry out a planned interruption of electricity supply from a Distribution-Scale Plant to the Distribution Network for a maximum duration of 32 hours in each case.
125. Planned outages without interruption of electricity supply from a Distribution-Scale Plant shall be performed if the latter is connected to the network through 2 or more 6 kV and higher voltage autonomous overhead (cables) lines.

126. The Distributor shall be obliged to restore the electricity supply from Distribution-Scale Plants to the Distribution Network after the unplanned interruption in no more than 48 hours.
127. The cumulative duration of planned and unplanned interruptions of electricity supply from Distribution-Scale Plants per year shall not exceed 87.6 hours.
128. The Distributor shall be required to take all possible measures to restore the electricity supply from Distribution-Scale Plants to the Distribution Network as soon as possible.

CHAPTER 22. ELECTRICITY SUPPLY INTERRUPTION AND RESTORATION REQUIREMENTS

129. The Distributor may interrupt the electricity supply of Customers due to planned and unplanned outages.
130. The Distributor shall be required to post on its website initial information on hours of planned electricity supply interruptions and restoration dates at least 7 days prior. The Distributor shall inform Customers of the planned electricity supply interruptions and restoration hours at least 2 days prior to the intended day of interruption through at least 1 nationwide TV Company 2 times per day: the first time in the period from 18:00 to 20:00 and the second time in the period from 20:00 to 23:00.
131. The Distributor shall provide information on electricity supply interruption and restoration hours via around-the-clock phone service, upon the Customer's call.
132. The Distributor shall perform planned interruptions on business days in the period from 9:00 to 17:00, but not more than for 6 hours.
133. Planned interruption of electricity supply shall be performed without interrupting the electricity supply of those Customers who are connected to the network through 2 or more 6 kV and above autonomously fed overhead lines (cables) or are fed from 2 stationary systems or sections of the plant (substation).
134. The Customer (except for residential Customers) and the Distributor, in mutually agreed procedures, shall have the right to set forth different timelines (days or hours) for planned interruptions, other than those defined in Provision 129 of the EDN Code, unless it leads to interruption or limitation of other Customers' electricity supply.
135. In case of an unplanned interruption of a Customer's electricity supply, the Distributor shall be obliged to restore it no later than:
    1) Within 2 hours for those Customers whose electricity supply is implemented with 2 or more 6 kV and higher autonomously fed overhead lines (cables) or from 2 stationary systems or sections of the plant (substation);
    2) Within 4 hours for Customers of residential settlements in administrative areas of urban municipalities, except for cases provided for in sub-Provision 1 of this Provision;
    3) Within 8 hours for Customers of residential settlements in administrative areas of rural municipalities, except for cases provided for in sub-Provision 1 of this Provision;
    4) Within 12 hours for Customers outside the administrative areas of residential settlements in urban and rural municipalities, except for cases provided for in sub-Provision 1 of this Provision.
136. The cumulative duration of planned and unplanned interruptions per year shall not exceed:
    1) 10 hours for those costumers whose electricity supply is implemented with 2 or more 6 kV and higher voltage autonomous overhead lines (cables) or from 2 stationary systems or sections of the plant (substation);
    2) 24 hours for other Customers within the residential settlements in the administrative areas of urban municipalities;
    3) 72 hours for Customers in residential settlements in the administrative areas of rural municipalities;
    4) 87.6 hours for all other Customers.
137. In all cases of planned and unplanned interruptions, the Distributor shall be required to take all possible

measures to restore the electricity supply as soon as possible.

138. The Distributor shall be obliged to register the reasons for, hours of, and duration of electricity supply interruptions and restorations (including cumulatively per year) and to reflect this information in the Customer's Registration Card.

CHAPTER 23. REQUIREMENTS ON TERMINATION AND RESTORATION OF CUSTOMER'S ELECTRICITY SUPPLY

139. The Distributor shall be obliged to terminate the Customer's electricity supply:
    1) Upon a written request from the Customer specifying the proposed duration of termination;
    2) Upon a written request from the entity with a title to the area of electricity supply (building, structure) specifying a proposed duration of termination if the Customer does not have a document certifying its title to the area requested by the EDN Code, by preliminarily notifying the Customer, except for the case specified in Provision 140 of the EDN Code;
    3) In case of termination of the Contract;
    4) In cases specified by Law and other normative legal acts.

140. If there is a dispute regarding the title to the area of electricity supply (building, structure), the issue of terminating the electricity supply according to Provision 139(2) of the EDN Code shall be decided, once the dispute is solved in procedures defined by the legislation. Where the dispute arose or the Distributor became aware of the dispute after the termination of supply according to Provision 139(2) of the EDN Code, the Distributor shall restore the electricity supply of the consumption system within 1 business day after being notified about the dispute.

141. The Distributor shall have the right to terminate the Customer's electricity supply:
    1) In case of a failure to make payments for consumed electricity according to the REM Rules;
    2) If the Customer did not provide the Distributor access to its premises, as is required by the EDN Code and REM Rules;
    3) By terminating the Contract, if the period specified in Provision 179(1) of the EDN Code is expired;
    4) In cases covered by the Law and other normative legal acts.

142. In cases when the Customer violates the time allowed for payment for electricity supplied and the Supplier's Customer violates the payment period for distribution services as specified in the REM Rules, except for cases defined in Provision 143 of the EDN Code, the Distributor shall have the right to suspend the Customer's supply by notifying the Customer at least 3 days in advance via television, official website, or any proper notification means specified in the EDN Code or by other available means such as placing announcements at entrances (construction sites) or postal divisions. Notification through TV shall be spread through at least one RoA public TV channel at least twice a day from 18:00 to 20:00 and from 20:00 to 23:00. If, according to the REM Rules, the Consumer has requested to receive its bill in writing or electronically, then the latter shall be notified in writing or via email. If, following the request of the Customer, the notification is delivered via the post office, then the associated charges should be covered by the Customer, and if it is sent via email, the service should be free of charge. The Distributor shall restore electricity supply without warning the Customerunless otherwise required by the Contract.

143. In instances of non-payment by a Consumer that has fixed emergency and/or technological capacity stated in the Contract, within the period specified in the REM Rules, the Distributor shall have the right to do the following:
    1) Restrict the Customer's electricity supply to the fixed emergency or technological capacity stated in the Contract by properly notifying the Customer at least 3 business days in advance;
    2) After the expiration of the period when, according to the Contract, the emergency and/or technological capacity supply is guaranteed, terminate the Customer's electricity supply by properly notifying the latter 3 days prior to the termination date.

144. Where the Customer violates the payment period defined in the Supply Contract, the Supplier shall duly apply to the Distributor at least 3 days prior to the intended termination date by sending a notification to the Customer as well.
145. Where the Supplier's application to the Distributor requesting to terminate the Consumer's electricity supply remains unchanged within the period defined in the REM Rules, the Distributor shall terminate electricity supply of the given Customer, and if it refers to Customers with emergency and/or technological capacity fixed in the Contract, the Distributor shall comply with procedures defined in the REM Rules.
146. Where the Distributor terminated the Customer's electricity supply according to Provision 141(1) of the EDN Code, the Distributor shall be obliged to restore the supply not later than:
    1) The same day before 18:00, if the Customer submitted to the Distributor a document verifying payment of its debt before 14:00 on a business day, or if the Distributor became aware from other reliable sources of debt payment by the Customer within the same period;
    2) The next day before 13:00, if the Customer submitted a document verifying payment of its debt after 14:00 on a business day, or if the Distributor became aware of debt repayment from other reliable sources in the same period;
    3) Within the shortest period possible but not later than 24 hours after being notified about the payment of the debt if the Customer submitted the payment confirmation document on non-business days or if the Distributor became aware of debt repayment from other reliable sources within the same period.
147. Where the debt is still not settled, the Distributor shall not terminate the Customer's supply if the latter presented payment guarantees acceptable for the Distributor or drafted a debt payment timetable with the latter. This provision does not restrict the Distributor's right to terminate the Customer's service in case of breach of the debt payment timetable, provided that the Supplier completed all the procedures described in this Chapter that precede the termination of electricity supply.

CHAPTER 24. AUTOMATED AND DISPATCH LOAD SHEDDING PROGRAMS

148. Unavoidable limitations of electricity supply of Customers shall be implemented by using Automated load shedding and/or Dispatch load shedding programs to be compiled and carried out in compliance with the EDN Code.
149. The decision on the application of electricity supply limitation programs for Customers connected to the Distribution Network shall be made by the Distributor's operator by providing information about volumes of such limitations to the ESO, as prescribed by the EDN Code, and to the Customers affected by these limitations, as prescribed by the REM Rules.
150. Electricity supply to the Customers shall be restored by the Distributor once agreed with the ESO.
151. Each year before December 1, the ESO and the Distributor shall revise the Automated and Dispatch Load Shedding programs to reflect the changes available. If the Automated and Dispatch Load Shedding programs have not been revised, then the previous year's programs shall remain effective for the next year.

SECTION 5. CONNECTION OF NEW CONSUMPTION SYSTEM AND CONNECTION OF GENERATOR AND AUTONOMOUS POWER PRODUCER TO DISTRIBUTION NETWORK

CHAPTER 25. GENERAL PROVISIONS

152. This section defines the procedures and terms of connection of consumption systems of Customers, Generators, and plants (capacities) of APPs to the Distribution Network, as well as of reconstruction of the Distribution Network resulting from reconstruction of the existing consumption systems of Customers or plants (capacities) of Generators and APPs.
153. To perform connection works, the Applicant shall submit a written application, either on paper or electronically, to the Distributor under procedures defined in the EDN Code and Annex 1.
154. The Distributor shall be required to place the connection conditions in visible places in all its service centers and on its official website.
155. All contracts specified in this section shall be concluded in writing or electronically, free of charge. Electronic contracts shall be signed with an electronic signature using a specific tool installed on the official website of the Distributor.
156. To balance the interests of the Applicant and Distributor, the Commission may make individual decisions on the connection to the network or on setting the connection fee based on the Distributor's or Applicant's application (supported with arguments), if agreed upon by the latter. The individual decision may not contain a discriminatory approach, if compared with similar cases.

CHAPTER 26. CONNECTING A CONSUMPTION SYSTEM OF THE CUSTOMER TO THE DISTRIBUTION NETWORK BY CONTRACT

157. Consumption system connection shall be carried out based on the Contract, except for cases provided for by Provision 160 and Chapter 27 of the EDN Code.
158. In case of connection by Contract, the consumption system connection works (as well as preliminary design and estimate; acquisition and placing of electric installations or commercial metering devices, including mounting the cells in other entity's electric installations; construction; testing; and commissioning thereof), as well as the actual connection costs of such works (hereinafter, the connection service), shall be implemented by the Distributor as follows:
    1) For an Applicant located in private houses and separate buildings who applied for connection to a 0.22 or 0.4 kV network—up to the entrance stand of the private house in case of overhead line access, or up to the entrance panel installed by the Customer on the external building wall in case of cable line access;
    2) For an Applicant who applied for connection to a 6(10) kV network—up to the entrance commutation device clamps of the Applicant's feeding substation in case of a cable line, and up to the isolators of the last in case of an overhead feeding line;
    3) For a multi-apartment building—up to the outlets of single-phase and three-phase metering devices.
159. The Applicant applying for the Contract shall submit an application (hereinafter, the Application), which should contain the following documentation and information:
    1) For a physical entity—name, surname, place of residence, copy of a document verifying identity, phone number, and address of the connection of the Consumption system; for a legal entity—name, location, phone number, address of the connection; for a legal entity and sole proprietor— the taxpayer identification number; and in case of electronic submission—the email address of the applicant shall also be specified;
    2) For a physical entity—copies of documents certifying (verifying) the Applicant's title or acquisition

of title to the consumption system location area (building, structure, plot), and for a legal entity—copies of documents certifying (verifying) the Applicant's title to the consumption system location area (building, structure, plot), except for areas of general use of multi-apartment buildings, including elevators;

3) To implement a Connection without a Connection Fee, a document verifying membership in a socially vulnerable family according to the GoA decision No.1122-N dated November 3, 2016;

4) The required active and reactive capacity (rated and used), voltage level, type of connection (single-phase, three-phase), consumption type (residential, non-residential), technical specifications of the system for non-residential consumption, as well as an indication about the Applicant's wish to have a back-up electricity supply ensured;

5) In case of connection to 0.4 kV or higher voltage level, a sketch of the Consumption system or the area layout, indicating the point or points of connection, while multi-apartment buildings must also include the internal consumption scheme, indicating the electricity metering points, number of stories in the building, number of apartments, other customers' rated capacity, and places of installation of electric panels and metering devices in the building;

6) For the Developer who has received an architectural planning permit—the Technical Conditions provided by the Distributor attached to the permit, and where a detailed connection design has been prepared based on the Technical Conditions, also that design.

160. In case the right of the Applicant (including ownership, use) to the area of installation of the Consumption System (including building, structure, plot) is not formalized in the manner prescribed by law, but there is a reference document issued by a competent body certifying the fact of residence of the Applicant in the area of location of the Consumption system, and in case of a garage, the fact of occupying the area, the Distributor assessing the feasibility of connecting the Consumption system to the electricity network and associated risks shall be entitled to conclude a Connection Agreement.

161. In case of non-compliance of the application with the EDN Code, as well as in cases when the Applicant's Connection contradicts the requirements of the normative legal acts, the Distributor shall reject it within the period specified in Provision 162 of the EDN Code, providing with relevant written justifications.

162. If no grounds are available for rejection of the Application according to Provision 161 of the EDN Code, the Distributor, upon receipt of the Application:

1) Where the application is delivered in person—immediately, and where the application is submitted by postal service—within 1 business day of receipt, except for cases provided for in sub-Provision 2 herein, shall issue an offer to the Applicant to conclude a Contract, along with 2 copies signed thereby;

2) Where an Application is submitted to connect a consumption system of 0.22 kV and 0.4 kV voltage or 6 kV and higher voltage to the network outside the residential area of the municipal administrative territory, or a Consumption system of the multi-apartment building under construction or that of a developing district, or if the submitted Application relates to the provision of a back-up electricity supply (hereinafter, the complex connection), shall within 5 business days develop the Technical Conditions and/or the electricity supply line direction and submit an offer to the Applicant for conclusion of the Contract along with 2 copies of the signed Contract. If the Distributor applies to the competent body due to the need to clarify the location of the Consumption system in the residential settlement, the Distributor shall notify the Applicant and the period specified in this sub-provision shall be terminated from the moment of application until the receipt of an answer from the competent body, by notifying the Applicant thereon.

163. Within 3 days of receiving the Contract referred to in Provision 162 of the EDN Code, if the Applicant agrees with it, he/she shall submit 1 signed copy of the Contract to the Distributor and from this moment forward the Contract shall be deemed signed. If, within 10 days of the Applicant having received the Contract, the copy of the Contract signed by the Applicant is not actually received by the

Distributor, this shall be considered as a refusal of the Applicant toward the Application.

164. The Applicant shall pay to the Distributor the Connection fee for provision of the Connection Service defined by Chapter 31 of the EDN Code, except for the socially vulnerable residential Applicants defined by GoA Decision N1122-N of November 3, 2016 whose Consumption Systems are located within the community administrative areas where a single-phase connection is provided.

165. In cases when, after the conclusion of the Contract in accordance with Provision 162(1) of the EDN Code, the Distributor discovers a case specified in sub-Provision 2 of the same Provision, the latter shall no later than within 5 business days of Contract conclusion provide a written proposal to the Applicant to make amendments to the Contract by sending him/her 2 copies of the agreement on amending the Contract (hereinafter, the Agreement), signed by the Distributor, which shall include the adjusted amount of the connection fee.

166. Within 3 days of receiving the proposal referred to in Provision 165 of the EDN Code, and if the Applicant agrees with it, he/she shall submit 1 copy of the signed Agreement to the Distributor. If within 10 days of the Applicant having received the proposal, the copy of the Agreement signed by the Applicant is not actually received by the Distributor, the latter shall terminate the Contract, notifying the Applicant thereof, and if the fee for connection to the Distribution Network has been already paid, it should be returned within 5 business days after the Contract is considered terminated.

167. The Contract shall be considered amended in accordance with Provision 166 of the EDN Code from the moment 1 copy of the Agreement signed by the Applicant is received by the Distributor.

168. In case of amendment of the Contract in accordance with Provision 166 of the EDN Code, the Distribution Network Connection period shall be calculated from the business day following the date when the calculated advance fee is paid in accordance with the connection fee adjusted in the Agreement, but not earlier than the date of the Contract amendment.

169. Within the timeframes specified in Provision 170 of the EDN Code, the Distributor shall:

1) Develop the required design and estimate documentation, and in case of simplified connection, the technical description of connection, except for cases when the Applicant in the design stage of the developing object has also implemented the operational design of the Distribution Network connection based on the Technical Conditions provided by the Distributor;
2) Carry out all the necessary agreements with state agencies, local self-government authorities, and any other party;
3) Carry out construction works to connect the consumption system to the distribution network, install metering devices, and notify the Applicant;
4) Receive, if needed, the decision (permit) for the operation of electric installations issued by the authorized body implementing the state technical supervision.

170. Based on the Contract mentioned in Provision 162 of the EDN Code, and in cases specified in Provision 166 of the EDN Code, the maximum period to ensure actual supply of electricity to the Applicant from the date of the advance payment (in the case of a Developer, the connection fee) set out by the Agreement, except for the cases referred to in Provision 164 of the EDN Code, shall not exceed:

1) 15 business days in the case of a simplified connection to a 0.22 kV distribution network and 50 business days in all other cases of connection to a 0.22 kV network;
2) 15 working days in the case of a simplified connection to a 0.4 kV distribution network, and 55 days in all other cases of connection to a 0.4 kV network;
3) 90 days for a connection to a 6(10) kV network;
4) 290 days for connection to a 35 kV network or connection of multi-apartment buildings under construction or developing districts.

171. In case of implementing a Connection without connection fees defined by the EDN Code or by the individual decision of the Commission, the periods referred to in Provision 170 of the EDN Code shall be counted from the moment of executing the Contract.

172. Within the Connection period defined in the Contract, the Customer shall be obliged:

1) To ensure the receipt of electricity and, in case of failure to do that, to inform the Distributor about its readiness to receive electricity;
2) In the case of connection to a 6(10) kV network, to provide to the Distributor the decision (permit) for the commissioning of the electric installations issued by the State Technical Supervisory Authority;
3) Present to the Distributor the persons in charge of the electric facility and the single-line scheme, in the case that such a requirement is defined by technical regulations.

173. In case of non-fulfillment of obligations provided for in Provision 172 of the EDN Code, the Distributor shall implement the actual connection of the Consumption system to the Distribution Network within 3 working days after the Customer is notified to be prepared to receive electricity and upon submission by the latter of the document referred to in sub-Provision 2 of the same Provision.
174. In the case that the deadlines specified in Provision 170 of the EDN Code are breached, within 3 business days from the occurrence of reasons for the breach, the Distributor shall notify the Applicant in writing about the reasons and the expected dates (or the possibility) to ensure electricity supply.
175. In the case that the connection of the consumption system to the Distribution Network requires an electricity supply line of higher voltage than the Applicant has requested or construction of a substation, the maximum period to ensure electricity supply (or its possibility) shall be accepted to be the period required for connecting the consumption system to the higher voltage network, as prescribed by Provision 170 of the EDN Code.
176. The main assets (property) created by the Distributor as a result of the connection are owned by the Distributor.
177. In the case that the Consumption system of the Applicant that separated from the consumption system of a Customer connected to the Distribution Network at 0.4 kV and higher voltage level is to be connected to the electric network without changing the capacity and the external feeding scheme, the Applicant shall submit to the Distributor the documents and information specified in Provision 159 of the EDN Code by making a note in the Application about being separated from the consumption system of the other Customer.
178. Upon receipt of the Application referred to in Provision 177 of the EDN Code, if there are no grounds for rejection of the Application mentioned in Provision 161 of the EDN Code, within 5 business days, the Distributor shall install the Commercial metering devices for the Applicant, the Customer and the Distributor shall make amendments to the Contract by proportionally reducing the contractual capacity of the Customer's consumption system connected to the Distribution Network, and the Distributor shall inform the Applicant of the opportunity to sign a contract on the provision of electricity distribution services and on universal supply of electricity, as prescribed by the REM Rules.

CHAPTER 27. CONNECTION OF THE CONSUMPTION SYSTEM OF A CUSTOMER TO THE DISTRIBUTION NETWORK WITH TECHNICAL CONDITIONS

179. The Customer's Consumption system shall be connected to the Distribution Network by obtaining Technical Conditions from the Distributor through the Applicant's own means in the following cases:
1) The Applicant's Consumption system shall be connected to the Distribution Network on a temporary basis (for construction works within the period specified in the Construction permit; for temporary trading purposes for a maximum of 6 months; for other purposes upon written consent of the Commission for a maximum of 1 year);
2) The Customer's consumption system is planned to be connected to 6 or 10 kV (outside the residential area of the community administrative territory) or to 35 kV electric network, and the Applicant, at its sole discretion, has expressed a wish to connect the consumption system to the electric network by obtaining Technical Conditions;
3) A new or reconstructed consumption system of 110 kV and higher voltage is to be connected to the Distribution Network;

4) A new or reconstructed consumption system of an entity holding a license for a public electronic communications network is to be connected to the Distribution Network;
5) A new consumption system with up to 0.5 kW rated capacity and 0.22 kV nominal voltage is to be connected to the Distribution Network, and the Applicant, at its sole discretion, has expressed a wish to connect the new consumption system to the network by obtaining Technical Conditions from the Distributor without installation of a metering device.

180. In cases specified in Provision 179(2–4) of the EDN Code, the Applicant shall submit to the Distributor the Application specified in Provision 159 of the EDN Code, and also authorization for the construction, in case of obtaining Technical Conditions for temporary connection required for the implementation of construction works, if obtaining such is required by legislation, by making appropriate notes in the application for provision of Technical Conditions. In cases specified in sub-Provisions 1 and 5 of Provision 179, instead of documents mentioned in Provision 159 of the EDN Code, the Applicant may submit a document or a contract verifying that the Applicant is performing activities in the area of location of the Consumption system.
181. Within 10 business days after the submission of the Application specified in Provision 180 of the EDN Code, the Distributor shall provide Technical Conditions or shall reject the Application in writing, presenting appropriate arguments thereon, if the documents and information submitted do not correspond to Provision 180 of the EDN Code or if providing Technical Conditions will contradict the requirements of normative legal acts.
182. A second independent supply shall be provided under the Technical Conditions if it is required by the Applicant's new consumption system design.
183. Upon completion of network connection works under the Technical Conditions, the Applicant shall ensure the receipt of electricity and shall submit to the Distributor documents referred to in Provision 172 of the EDN Code, and within 3 business days after the documents are submitted, the Distributor shall implement actual connection.

CHAPTER 28. ISSUANCE OF REFERENCE

184. To obtain a reference, the Applicant shall apply to the Distributor and provide information on the type, name, planned capacity, and location area of the plant and a document verifying payment of a relevant fee to the Distributor for provision of the Reference.
185. The Reference shall be developed and issued based on the requirements of the technical regulations of the RoA, the reliability indicators submitted by the Applicant, as well as the requirement to carry out connection or reconstruction of electrical installations at the lowest cost.
186. The Distributor shall issue the Reference within 10 working days after the submission by the Applicant of the complete information (documents) mentioned in Provision 184. In a case where it is necessary to obtain the consent of the Transmitter, the ESO, or the EMO, the mentioned period may be extended for another 10 working days, while the Distributor shall duly inform the Applicant.
187. The issuance of the Reference shall be rejected within 10 working days from the moment of receiving the application mentioned in Provision 184 if the Applicant has not submitted the complete information (documents) mentioned in the same Provision.
188. For issuance of the Reference, the Distributor shall charge the Applicant a service fee in the amount of 250,000 AMD (including value added tax (VAT)), which is refundable within 5 working days only if the application is rejected as described in Provision 187.
189. The Reference shall include at least the following information:
1) Name of the applicant (name, surname);
2) Name, type, capacity of the plant, location area (region, community, settlement);
3) The connection point with the network, the required voltage level, and the length of the planned power transmission line;

4) Reasonable measures for strengthening the existing electric network to satisfy the conditions of the new connection (increase in the cross-sectional area of the wires, replacement of power transformers, installation of additional cells, etc.);

5) Validity period of the Reference.

190. Proposals for the reconstruction of electric installations (including relay protection and automation devices) under the operative subordination of the ESO shall be developed by the ESO based on the requirements of the Network Codes.

191. Consent of the Transmitter, ESO, and EMO required for issuance of the Reference shall be obtained by the Distributor.

192. The validity of the Reference shall be 6 months starting the day of issuance.

193. The validity of the Reference may be extended only once. To do so, the Applicant shall apply to the Distributor for an extension no earlier than 10 working days before the expiration of the Reference validity, paying the amount specified in Provision 188, and the Distributor shall extend the validity of the Reference for another 6 months within 3 days after the receipt of the application but not later than the expiration date.

194. Throughout the Reference validity period, the capacity specified in the Reference is considered reserved by the Applicant at the connection point, and in case the latter obtains a license for electricity generation, the capacity of the given plant in the Distribution Network at the connection point stated in the Reference shall be considered reserved until the Technical Conditions are provided.

195. After the expiration of the Reference, the Applicant shall be eligible to apply to the Distributor again, following the requirements described in this Chapter, to receive a new Reference.

196. If the Applicant obtains a license for electricity generation during the validity of the Reference, the Technical Conditions shall be provided to the Applicant in accordance with the Reference unless otherwise decided by mutual agreement of the parties.

CHAPTER 29. CONNECTION OF GENERATORS

197. Connection of the Generator shall be implemented based on the Contract and, in a case where the plants have an electricity purchase guarantee, according to model forms defined by the Commission.

198. To receive Technical Conditions for the Generator's connection, the Generator shall submit an application to the Distributor, enclosing the data referred to in Annex 2 of the EDN Code, as well as the following:

1) A copy of the operation license issued by the Commission, if it is required by the Energy Law and the Licensing Law for operations carried out by the Generator;

2) Copies of documents confirming (verifying) the title of the Generator to the area where the connected capacity is located.

199. Within 15 business days after submission of the Application, if the Application does not comply with Provision 198 of the EDN Code, or if the connection of the Generator contradicts the requirements of legal acts, the Distributor shall reject the Application in writing, presenting corresponding arguments; if there are no such arguments, the Distributor shall do the following within the same period:

1) Develop Technical Conditions in compliance with the requirements of technical regulations, and, if necessary, coordinate them with the Transmitter and ESO;

2) In cases defined by the Commission, calculate the Generator's initial connection fee to be decided based on the aggregated estimation of the Generator's connection fee referred to in Annex 3 of the EDN Code;

3) Submit an offer for conclusion of a contract along with 2 copies signed by the Distributor.

200. Construction works between the Generator's plant and the Connection point shall be implemented by the Generator pursuant to the design (connection scheme) prepared in accordance with the Technical Conditions provided by the Distributor.

201. In the case of licensed Generators, the Technical Conditions shall be provided by the Distributor for the period of construction of the plant stated in the Generation License, and shall be extended, if the mentioned period is extended, by the same period and on the same terms, and in other cases

the Technical Conditions shall be provided for 2 years.

202. The Generator shall pay a Generator Connection fee to the Distributor, calculated as sum of expenditures for construction of new capacities and reconstruction of the existing ones (including design) within the Distribution Network necessary for the connection of the Plant to the Distribution Network. If, based on the necessity of further development of the Distribution Network, it is planned to extend the network infrastructure, exceeding the parameters required for connection of the Plant to the Distribution Network, then the expenses to be implemented by the Distributor in this regard shall not be considered in the calculation of the Generator's connection fee.

203. Technical Conditions shall be developed based on the principle of implementing the necessary works on connection (reconstruction) of the Plant (construction of a new network and reconstruction, upgrade, and extension of the Distribution Network) at the least cost for the parties. If, based on the necessity of further development of the Distribution Network, the Distributor is planning to extend the network infrastructure, then Technical Conditions shall be provided considering the availability of the new infrastructure. The works aimed at the development of the mentioned infrastructure shall be included in the Distributor's investments plan and shall not be considered in the calculation of the Generator's Connection fee.

204. The Generator shall ensure the compliance of the Plant (capacity) being connected to the Distribution Network with the requirements of the EDN Code and the technical regulations.

205. Within 20 days from receipt of the contract in accordance with Provision 199 of the EDN Code, the Generator, if he/she agrees with the contract, shall submit one signed copy of the contract to the Distributor. If the Distributor does not receive a copy of the contract signed by the Generator within 30 days after the Generator received the offer for a contract, it shall be considered a refusal by the Generator regarding the Distribution Network connection application.

206. If, under the Commission's resolution, a model contract is developed for the given type of plant, then the following shall be mandatorily specified in the contract:
    1) The period for submission of the connection design that has been reviewed by experts, for coordination with and obtaining the opinion of the Distributor;
    2) The initial size of the connection fee and payment periods (schedule), as well as the mechanisms of adjustment of the initial and final amounts of the Connection fee;
    3) The Generator's Connection timeframes and, in case of violations of these timeframes, the responsibilities of parties.

207. The relationship associated with payment of the Connection Fee in the instances defined by the Commission shall be regulated by the contract.

208. The reconstructed or newly constructed capacities of the Distribution Network shall be the property of the Distributor, while the installed Metering Complex, as well as the devices and relevant software required for connecting to the automated metering system of the Distribution Network, shall be the property of the Generator.

209. During the development (modification) of the construction (reconstruction) design of the plant, in case of changes in the technical parameters, the Generator shall inform the Distributor in advance about the changes in writing to make relevant changes in the Technical Conditions, if necessary. Within 15 days following the receipt of the application, the Distributor shall provide to the Generator the modified Technical Conditions or the conclusion on leaving those unchanged, and where necessary, also the changed amount of the Generator's Connection fee along with relevant justifications. If the Generator agrees, the parties shall make corresponding amendments to the Contract, and in case of disagreement, the Technical Conditions shall be left unchanged, or the Contract shall be terminated. Moreover, in case of a positive difference between the expenses actually incurred by the Distributor and the Advance fee, such difference shall be compensated by the Generator, while in the case of a negative

Difference, the Distributor shall return it to the Generator within 5 business days after submission of the conclusion referred to herein.

210. The Generator, following the Technical Conditions, shall perform the works required to connect the Plant to the Distribution Network (including design and construction), and in order to obtain permission for actual connection (putting under voltage) (hereinafter, the Connection permit), the Generator shall apply to the Distributor at least 70 business days prior to the end of validity of the Technical Conditions by submitting the following:
    1) Application for Connection permit,
    2) In cases envisaged by the laws, a copy of the conclusion on commissioning of the electric installation issued by the State Technical Supervisory Authority;
    3) The connection action plan;
    4) Protocol (tripartite act) about mounting or replacing the electricity (capacity) Metering Complexes.
211. Within 10 business days of having received the application referred to in Provision 210 of the EDN Code, the Distributor shall verify the compliance of the documents submitted by the Generator with the requirements of the EDN Code.
212. For power plants with installed capacity of 10 MW and above, the Distributor shall submit the documents referred to in Provision 210 of the EDN Code to the ESO for approval within the period specified in Provision 211 of the EDN Code.
213. Within 5 business days of receiving documents referred to in Provision 210 of the EDN Code from the Distributor, the ESO shall inform the Distributor about his/her consent or the shortcomings revealed.
214. Within the timeframe specified in Provision 211 of the EDN Code and in the case mentioned in Provision 212, the Distributor shall, within 5 business days after having received the opinion of the ESO, issue a Connection permit to the Generator (if the conclusion is positive) or inform the Generator about the shortcomings revealed (if the conclusion is negative).
215. If the Generator fails to correct those shortcomings within a reasonable timeframe after having received the notice about shortcomings revealed, but not later than 20 business days before the deadline under the Technical Conditions, the Connection permit shall not be issued. If the timeframe envisaged in this provision is violated by the Generator, the duration of works to be completed by the Distributor shall be extended as much as the violated period.
216. Within 5 business days of having received the Connection permit, the Generator shall submit a written application to the Distributor, and in the case provided for under Provision 212 of the EDN Code, also to the ESO, indicating the preferred dates of actual connection of the Plant to the Distribution Network (putting under voltage).
217. If the preferred date of actual connection of the Plant to the Distribution Network (putting under voltage) as specified by the Generator is not acceptable for the ESO from the perspective of ensuring the reliability and safety of the power system, the ESO shall, within 3 business days, negotiate with the Generator about moving the date of actual connection (putting under voltage), which cannot exceed 10 business days from the preferred date mentioned by the Generator.
218. The actual connection of the Plant to the Distribution Network shall be performed in accordance with the design (connection scheme) prepared based on the Technical Conditions and in accordance with the connection action plan agreed with the Distributor (in cases provided for by the EDN Code, also with the ESO). The technical parameters of the actual connection of the Plant to the Distribution Network shall be fixed in the Contract.
219. Changes in the Technical Conditions and technical parameters of the Plant can be performed exclusively upon the consent of the Parties, except for cases when such changes are essential for complying with the requirements of laws and regulatory legal acts.

CHAPTER 30. CONNECTION OF AUTONOMOUS POWER PRODUCERS

220. For connection of an Autonomous Power Producer (hereinafter, APP), the latter shall submit an Application to the Distributor along with the data required for the replacement of the Commercial meter with a reverse meter:
    1) Data on the Registration Card;
    2) Data on the Plant's capacity.

221. The Distributor shall check the compliance of the provided data with the requirements of the Law and, in case of compliance, within 3 business days shall provide an account number to the APP for payment of a charge defined in Provision 257(3) of the EDN Code, and in case of detecting non-compliance, shall reject the Application, providing reasons for the rejection.

222. After receiving the payment verification document, the Distributor shall install a reverse meter according to procedures described in Chapter 34 of this Code.

CHAPTER 31. CONNECTION FEES

223. Connection fees for the Customer of a 0.4 (0.22) kV voltage consumption system shall be determined by the following formula:

$$CF = F_{st} + F_{add} + F_{res} ,$$

where:

F_{st} is the standard component of the connection fee for connecting the Consumption System to the Distribution Network located within the administrative area of the residential community, regardless of the distance from the network connection point, and beyond the administrative area of the residential community at a distance of up to 200 meters from the network connection point (including, but not limited to the costs for design and estimation, electrical installations, including purchase and installation of cells, electronic commercial metering devices, automatic switches in other people's electrical installations, as well as construction (including of transmission line), testing, and commissioning costs), according to Annex 4 of the EDN Code.

F_{add} is the additional component of the connection fee, which shall be accepted as equal to 0 within the administrative area of the residential community. Beyond the administrative area of the residential community, F_{add} shall include:

1) The average cost of construction of a power transmission line, at a distance exceeding 200 meters from the network connection point;
2) The average cost of construction of infrastructure, if it is necessary to construct a substation and a higher voltage feeder line other than that initially requested by the New Customer or Developer or Customer based on the Feasibility Study of the project on connecting the Consumption System to the Distribution Network (hereinafter, the FS).

F_{res} is the average cost of constructing a power transmission line providing reserve feeding to the Consumption System.

224. The values of the F_{add} and F_{res} components shall be determined by the length of the constructed lines and the average costs of the constructed substation. The average values per units of lines and substations under construction shall be published on the official website of the Distributor and shall enter into force on the date of publication.

225. The connection fee for a multi-apartment building shall be determined by the following formula:

$$CF = AC + (F_1 n_1 + F_2 n_2) C_{cu} + \sum_{k=1}^{n_3} F_3$$

where:

AC is the cost of the area required for mounting the substation, in cases when, for connection of a multi-apartment building to the Distribution Network, it is necessary to construct a substation.

F_1 is the connection fee for 1 Consumption System in a multi-apartment building with 10 kVA single-phase connection (including, but not limited to the meter box, electronic commercial metering device, and automatic switches), according to Table 2 of Annex 4 of the EDN Code.

n_1 is the total number of consumption systems in the multi-apartment building, each of 10 kVA single-phase connection.

F_2 is the connection fee for 1 Consumption System in the multi-apartment building with 14 kVA single-phase connection (including, but not limited to the meter box, electronic commercial metering device, and automatic switches) according to Table 2 of Annex 4 of the EDN Code.

n_2 is the total number of consumption systems in the multi-apartment building, each of 14 kVA single-phase connection.

C_{cu} is the coefficient of costs and unutilized capacity, which is accepted as equal to 3 in the administrative area of Yerevan City, and equal to 1 in any other territory in the RoA.

F_3 is the connection fee for apartments in a multi-apartment building or for commercial customers (including electrical equipment for general use) with a 3-phase connection (0.4 kV voltage), including but not limited to the meter box, electronic commercial metering device, and automatic switches, which is calculated by the formula set out in Provision 2 of Methodology 1 of Annex 4 of the EDN Code separately for each commercial connection point, according to the number of Commercial metering devices.

n_3 is the total number of apartments in the multi-apartment building and commercial Customers for which a 3-phase connection (0.4 kV voltage) is intended.

226. Distribution Network Connection fees for Consumption systems of new units that have been added as a result of reconstruction to the separate units of a multi-apartment building (apartments, non-residential premises) by the owners thereof after the mentioned separate units became the real estate title registration objects shall be calculated by the following formula:

1) For a 10 kVA single-phase connection:

$$CF_1 = F_1 * C_{cu}$$

2) For a 14 kVA single-phase connection:

$$CF_2 = F_2 * C_{cu}$$

3) For a 0.4 kVA connection:

$$CF_3 = F_3$$

227. Distribution Network Connection fees (VAT included) for 6(10) kV voltage Consumption Systems of Commercial Customers shall be determined by the following formula:

$$CF = F_{st} + F_{add} + F_{res} ,$$

where:

F_{st} is the standard component of the connection fee for connecting the Consumption System located at a distance of 1,200 meters from the network connection point (including, but not limited to the costs for design and estimation; electrical installations, including purchase and installation of cells, switches, and electronic commercial meters (except for current and voltage transformers located at the premises under control of the Customer) in other people's electrical installations; as well as construction (including power transmission line), testing and commissioning costs) according to the Annex 4 of the EDN Code.

F_{add} is the additional component of the Distribution Network connection fee, which shall include:

1) The average cost of construction of a feeding transmission line at a distance exceeding 1,200 meters from the network connection point;

2) The average cost of construction of infrastructure beyond the administrative area of the residential community, if it is necessary to construct a substation and a higher voltage feeder line than the one required by the Applicant based on the FS.

F_{res} is the average cost of constructing a power transmission line providing reserve feeding to the Consumption System.

228. The values of the F_{add} and F_{res} components shall be determined by the length of the constructed lines and the average costs of the constructed substation. The average costs of the units of lines and substations under construction shall be published on the official website of the company and shall enter into force on the date of publication.

229. Connection fees for a Consumption System to be connected to a 35 kV distribution network shall be determined by the following formula:

$$CF = F_{st} + F_{add} ,$$

where:

F_{st} is the fee for a standard connection for which construction of a single-chain overhead line with length of up to 12 km is envisaged, according to Table 4 of Annex 4 of the EDN Code.

230. For a standard connection, installation of a Metering Complex with an electronic meter shall be envisaged.

231. If the capacity requested by the Applicant is less than 3,000 kVA, the standard connection fee shall be accepted as equal to the connection fee defined for 3,000 kVA. If the requested capacity is greater than 15,000 kVA, the standard connection fee shall be accepted as equal to the sum of standard connection fees set for the capacities necessary to ensure the requested capacity.

232. If the connection of the Applicant's Consumption System is carried out within the range of standard connection parameters set out in Provision 229 of the EDN Code and in Table 4 of Annex 4 of the EDN Code, the value F_{add} shall be accepted as equal to 0.

233. If the length of connecting line exceeds the length specified in Provision 229 of the EDN Code, then

$$F_{add} = \Delta F \times n,$$

where:

n is the number of 250-meter segments exceeding the specified length for standard connection.

ΔF is the fee defined for every 250-meter segment exceeding the specified length for the standard connection (Table 4 of Annex 4 of the EDN Code).

234. If the Feasibility Study for the Applicant's Consumption System connection design provides for the construction of a higher voltage feeder line and a lower substation than the one required by the Applicant, F_{add} shall be accepted as equal to the difference of the estimated values of the calculated costs for construction of the power distribution line based on the parameters envisaged by the FS and the standard connection specified in Provision 229 and Table 4 of Annex 4 of the EDN Code.

235. If the Applicant's Consumption System design provides for a reserve feeding line, F_{add} shall include the full costs of construction of reserve lines.

SECTION 6. PROCEDURES ON INSTALLATION, REPLACEMENT, AND TESTING OF METERING DEVICES OF CUSTOMERS

CHAPTER 32. GENERAL PROVISIONS

236. The costs and responsibility for the purchase, installation, replacement, and operation (including maintenance, accuracy testing, checking and verification, renovation, and safety) of Commercial metering devices (except for 6 kV and over current and voltage transformers that are the property of a Customer) shall be borne by the Distributor regardless of who they belong to, except in instances specified in Provisions 270 and 271 of the EDN Code.

237. Commercial metering of electricity in the REM shall be carried out by the Distributor, in cases and procedures defined in the REM Rules.

238. Every Metering point should be equipped with a Metering device, except for cases when the rated capacity of the customer's consumption system does not exceed 0.5 kW and the nominal voltage does not exceed 0.22 kV, implementing metering of consumed electricity by the rated capacity of the Customer's consumption system during the working hours of the installed equipment. In the case envisaged in this Provision, the Registration Card shall include the description, capacity, and working hours of the Customer's consumption system.

239. Requirements for the metering devices of the Customer (except for the Qualified Customer) shall be specified in the EDN Code and other legal acts regulating the sector.

240. Commercial metering of the Generator shall be carried out by the EMO in procedures defined in the WEM Rules and ETN Code and other legal acts regulating the sector.

241. The Commercial metering device shall be designed to ensure metering of active energy component, and in the case of 0.4 kV and higher voltage networks, the reactive energy component as well.

242. Relations pertaining to the metering devices included in the automated electricity (capacity) metering system shall be governed by the ETN Code and the EDN Code.

243. The costs of ensuring the integrity and maintenance of metering devices during their operation shall be borne by the Customer, if the latter is not a Customer in a multi-apartment building, the metering device is located within the premises owned by or under control of the Customer, and it is reflected in the Registration Card.

244. The Customer shall provide to the Distributor access to its premises to perform operations with Metering devices as prescribed in the EDN Code. To access the Customer's premises, the Distributor shall duly notify the Customer at least 24 hours in advance, unless otherwise provided by the REM Rules or the EDN Code. The Distributor shall coordinate the date of these operations with the Customer. To enter the Customer's premises, the Distributor's representative shall present to the Customer a document with a photo certifying his/her authority. The operations with the Metering devices on the Customer's premises shall be performed in the presence of the latter's representative. In the case of repeated unreasonable refusal of access, the Distributor shall be eligible to terminate (restrict) the Customer's electricity supply by notifying the latter in advance as prescribed by the EDN Code.

CHAPTER 33. GENERAL DESCRIPTION OF THE AUTOMATED SYSTEM OF ELECTRICITY METERING AND CONTROL (DAMS)

245. The DAMS shall provide for the following:
   1) Transfer data in electronic format to the metering database;
   2) Record data from metering devices and maintain their confidentiality;
   3) Register and ensure availability of data recorded in the database and related to Customers;
   4) Register the quantity of electricity at each Metering Point of the REM.

246. The electricity Commercial (Control) Metering devices included in the DAMS shall be approved for

commercial metering in the RoA and shall comply with the requirements of the ETN and EDN Codes.

247. The Metering database shall include:
   1) Records on active and reactive energy passing through the Metering Point and voltage levels, based on aggregate (integral) data received within 30-minute intervals, as well as on the power factor within the same interval;
   2) Information on changes in the metering database records and on persons who perform the changes;
   3) Information on each electricity Metering device (technical characteristic of the Metering device, schedule of calibrations and testing, manufacturer's serial number, etc.)
248. The DAMS shall be managed by the DAMS Chief administrator through the DAMS administrators.
249. The DAMS Chief administrator may reprogram the electricity Metering device if, as a result of self-diagnosis, a program error has been revealed.
250. The Distributor and the REM Participants shall bear responsibility for keeping the confidentiality of login passwords for the DAMS.
251. The DAMS Chief administrator and DAMS administrators shall be required to archive the metering database from servers once every 3 months.

CHAPTER 34. REQUIREMENTS FOR METERING DEVICES OF THE CUSTOMERS; INSTALLATION AND REPLACEMENT CONDITIONS

252. The Commercial Metering device of the Customer shall be placed in an individual or shared box in a way to ensure the visibility of readings of the Metering device. Such boxes should be locked by the Distributor. If the Customer's Commercial (Control) metering device is located in an individual box, the Customer shall be entitled to seal it.
253. The Customer's Commercial Metering device, including the clipboard of the Commercial Meter, shall be sealed by the Distributor, except for those meters that are included in the DAMS, where the clipboard is sealed electronically. The Customer shall be entitled to additionally seal the Commercial metering device, while the Distributor shall be entitled to seal the Control metering device, including the clipboard of the Control meter.
254. The Metering device can be replaced at the initiative of the Customer, as well as the Distributor.
255. Replacement of the Metering device at the initiative of the Distributor shall be done at the expense of the latter.
256. Replacement of the Metering device or its inclusion in the DAMS at the initiative of the Customer shall be done by the Distributor, based on the written request from the Customer, and upon the payment made as prescribed in Provision 257 of the EDN Code, which should be returned after 1 year of replacement of the Customer's Metering device, deducting that amount from the cost of services provided.
257. Replacement of the Commercial metering devices or their inclusion in the DAMS upon the request of the Customer shall be done upon the payment of the following charges:
   1) Replacement of a single-phase induction meter by a single-phase electronic meter: 10,000 (ten thousand) AMD;
   2) Replacement of a 3-phase induction meter by a three-phase electronic meter: 35,000 (thirty-five thousand) AMD;
   3) Replacement of a single-phase meter by a single-phase multi-tariff reverse meter for implementation of power flow exchange between the APP and Distributor provided for by the Law: 11,000 (eleven thousand) AMD, and in case of replacement of a 3-phase meter by the multi-tariff 3-phase reverse meter: 55,000 (fifty-five thousand) AMD;
   4) Replacement of a 0.22 kV meter of the Customer with a meter complex (with communication devices, monitoring enabling software) required for connection to the DAMS: 60,000 (sixty thousand) AMD;

5) Replacement of a 0.4kV meter of the Customer with a meter complex (with communication devices, monitoring enabling software) required for connection to the DAMS: 80,000 (eighty thousand) AMD.
6) Replacement of a 6kV and higher voltage meter of the Customer with a meter complex (with communication devices, monitoring enabling software) required for connection to the DAMS: 300,000 (three hundred thousand) AMD.

258. Within 10 business days after receiving the request mentioned in Provision 256 of the EDN Code and the document certifying the payment as per Provision 257 of the EDN Code, the Distributor shall:
1) Replace the Commercial metering device;
2) Make the corresponding amendment to the Registration Card, stating the data of the Commercial metering device replaced.

259. To balance the interests of the Customer and Supplier, the Commission may make individual decisions regarding the process of replacing Commercial metering devices in case of applying to the state and municipal administration bodies within the framework of implementation of state, community-scale, or international assistance programs.

CHAPTER 35. PROCEDURE FOR TESTING METERING DEVICES

260. The testing of commercial metering devices may be carried out at the initiative of the Customer, as well as the Distributor. The performance accuracy of the commercial metering device shall be certified based on the conclusion of the metrological authority on the results during regular or extraordinary testing of the commercial metering device.

261. Regular testing of commercial (Control) meters as well as current and voltage transformers shall be carried out according to the RoA legislation.

262. All costs related to performance accuracy checking and calibration of the commercial metering device shall be borne by the Distributor, regardless of who they belong to, except for the cases set out in Provisions 271 and 272(2, 3) of the EDN Code.

263. Not later than 3 business days before dismantling (including installation of a new one), accuracy checking, and testing of the commercial metering devices, the Distributor shall be obliged to appropriately notify the Customer about the dates. The Distributor shall be eligible to dismantle the commercial metering device without prior notification of the Customer if it was detected that the Customer consumes the electric power with an obvious violation of the commercial metering device. In such cases, the Distributor shall properly notify the Customer at the earliest possible opportunity by presenting its substantiations for dismantling the commercial metering device.

264. The Customer shall be entitled to require, by way of advance notification, that the Distributor perform any work related to the commercial metering device (dismantling, accuracy checking, or testing) in his/her presence at a mutually pre-agreed time, but no later than 3 business days after being properly notified about it. In the event that the duly notified Customer fails to appear at the specified time, the works shall be performed in his/her absence.

265. In case of dismantling of the commercial metering device, the Distributor shall:
1) Prepare the protocol (act) on the commercial metering device readings and its integrity or damages, which shall be signed by the Distributor and the Customer. In case of disagreement with any provision of the protocol (act) by the Customer, a relevant note shall be made about it in the protocol (act), describing the reasons for the disagreement. The protocol (act) shall be produced in two copies, one copy for each party. In the case of the Customer's absence, the Distributor shall attach the proof of the Customer's notification to the protocol (act) and make a relevant note in the protocol (act) about the failure of the Customer to appear for the dismantling of the commercial metering device;
2) Install another device at least equivalent to its own commercial metering device, the data of which shall be fixed in the Registration Card;
3) Participate in the Commercial metering device testing and preparation of a conclusion together with

the metrological authority, which shall include information about the integrity of or damages to the device, actual readings, and the results of testing.

266. In the case of checking and verifying the Commercial metering device, the Distributor, after dismantling the device, shall be required not later than:
    1) Within 15 business days, to provide to the Customer a copy of the expert conclusion of the Metrological authority on the results of testing (inspection) and include it in the Customer's Registration Card,
    2) Within 35 business days, to provide to the Customer all information required for recalculation, if the violation of the metering device is confirmed;
    3) Within 60 business days, to provide to the Customer all information required for recalculation, if the average daily consumption considered for recalculation purposes has been determined for the first month of consumption following the restoration of the Commercial metering device.
267. The testing shall not be carried out if dismantling the metering device is stipulated by implementation of metering device replacement works according to investment programs of the Distributor approved by the Commission. In this case, the dismantled metering devices shall be preserved by the Distributor for at least 3 months if the Customer was present during the dismantling, and for 6 months if the Customer failed to appear for the dismantling works. Upon the request of the Customer, the Commercial metering device shall be subject to testing within the specified period under procedures defined by the EDN Code.
268. In case of replacement of the Commercial meter, the Distributor shall be entitled to suspend the electricity supply of the Customer not more than for 1 hour to replace the Commercial meter, and not more than 3 hours to replace the current and voltage transformers. If the Customer has fixed contract-based emergency or technological capacity, then the Distributor, in order to restore the Commercial metering device, shall be obliged to agree on the terms for suspension and restoration of electricity supply with the Customer. In this case, the Customer shall be obliged, based on the Distributor's written request, no later than 5 business days from receipt of the request, to enable the latter to replace the commercial metering device.
269. The Distributor shall be obliged to dismantle (replace) the Commercial metering device no later than 5 business days from receipt of the Customer's written application on the necessity to test the commercial metering device after properly notifying the Customer about it at least 1 day in advance.
270. If a Customer has filed more than 1 application over 2 consecutive years for testing of its Commercial metering devices as well as current and voltage transformers, he/she shall be obliged to make an advance payment of 1,200 AMD (including VAT) to the Distributor. If the fact of violation of the Commercial metering device is confirmed by the expert conclusion provided by the metrological authority, the Distributor shall consider the abovementioned advance payment in the Customer's bill for consumed electricity. If the fact of violation is not confirmed, the advance payment will be considered as a service charge paid to the Distributor for testing the Commercial metering device and shall not be refunded to the Customer.
271. The provisions outlined in this Chapter shall not limit the right of the Customer to order, at its own expense, testing and inspection of the Commercial metering devices (meters as well as current and voltage transformers) attributed to its electricity consumption system from other companies entitled to carry out testing (inspection) of metering devices. In such a case, the Distributor shall be obliged to ensure the realization of the Customer's right set forth in this Provision according to the following procedure:
    1) Within 5 business days after the receipt of the written request of the Customer, the Distributor, together with the Customer, shall dismantle, pack, seal, and hand over the Commercial metering device to the Customer, replacing it with another, at least equivalent commercial metering device. In case of the absence of the Customer during the dismantling process, the Distributor shall prepare a protocol on the failure of the Customer to appear. In this case, the dismantling of the commercial metering device shall not be performed;

2) The Customer, no later than in 20 business days following the dismantling, shall return to the Distributor the commercial metering device, calibrated and certified (sealed) by the metrological authority, and the written conclusion of the competent agency about the results of testing (inspection) to be verified by the metrological authority. In a case when the conclusion of the testing confirms the violation of the commercial metering device, the Distributor shall be obliged to follow the procedures defined in Chapter 17 of the REM Rules.

3) In the case provided for by this Provision, the Distributor shall be entitled to participate in the process of testing (inspection) of the commercial metering device. If the Distributor expressed its willingness to participate in the testing (inspection), the Customer shall notify the Distributor in a proper way defined in the EDN Code about the time and place of testing at least 3 business days beforehand. If the Distributor fails to appear after having been properly notified about the time and the place of the testing (inspection) of the commercial metering device, then this shall not be a basis for not implementing the testing;

4) If the Customer fails to return the commercial metering device to the Distributor within 35 business days, then the Distributor shall be entitled to apply a penalty to the Customer in the amount of double the cost of electricity for the month with the highest consumption over the last year. If no electricity was consumed by the Customer, the penalty shall be calculated in the amount of double the cost of electricity for the first month with consumption after the restoration of the Commercial metering device. At the same time, the Distributor shall be entitled to require that the Customer compensate the damage incurred, including the cost of the commercial metering device, costs related to its dismantling, and other costs.

272. The Distributor shall be obliged to check and adjust the hours of the electronic Commercial meters at least once per year so that they accurately meter the quantities of electricity consumed during daytime hours and nighttime hours (in corresponding time intervals).

SECTION 7. PENALTIES APPLIED TO THE DISTRIBUTOR

CHAPTER 36. PENALTIES APPLIED TO THE DISTRIBUTOR FOR VIOLATION OF REQUIREMENTS OF THE EDN CODE

273. The Distributor shall pay a penalty to the Customer or Applicant:
   1) For each case of violation of procedures or schedules for implementation of planned/unplanned interruptions and restorations of electricity supply defined in Chapter 22 of the EDN Code;
   2) For each case of violation of procedures or schedules for termination and restoration of electricity supply defined in Chapter 23 of the EDN Code;
   3) For each case of violation of procedures or schedules for installation and replacement of Commercial metering devices defined in Chapter 34 of the EDN Code;
   4) For each case of violation of procedures or schedules for testing of Commercial metering devices defined in Chapter 35 of the EDN Code;
   5) For each case of violation of procedures or schedules defined in Chapter 30 of the EDN Code;
   6) For violation of periods defined in Provisions 170, 173, 174, and 183 of the EDN Code;
   7) For violation of periods defined in Provisions 178 of the EDN Code;
   8) For each violation of procedures and timeframes for submission of notifications (information) and sharing of documents defined in the EDN Code, unless it is covered by cases of violations described in other sub-Provisions of this Provision.

274. The Distributor shall pay the following amounts of penalty in cases referred to in Provision 273 of the EDN Code:
   1) In the case of a Customer: 50 percent of the average monthly cost of electricity consumed, not exceeding 2,500 AMD;
   2) In the case of an Applicant: 2,500 AMD, except for Provision 273(6) of the EDN Code, where the Distributor shall pay a penalty to the Applicant for each delinquent day equal to 0.5 percent of the Connection fee, not exceeding the total amount of the Connection fee.

275. The Distributor shall consider the calculated penalty as follows:
   1) In the case of a Customer: in the bill for electricity consumed by the latter during the current month. The calculated penalty shall be mentioned in a separate line and shall be deducted from the cost of electricity supplied, and in the case of a Supplier's Customer, from the cost of distribution services provided.
   2) In the case of an Applicant: within the period defined by the REM Rules for the payment against electricity consumed during the month following the connection of the Consumption system of the latter to the electric network, and if it failed to become a Customer, before the end of the month preceding the violation, in cash.

276. The Distributor shall not pay a penalty for the mentioned cases if they were caused by force majeure consequences, as well as in case of non-fulfillment by the Applicant of the requirements referred to in Provision 172 of the EDN Code or if the electricity supply of the Customer's Consumption system was terminated in procedures defined in Chapter 23 of the EDN Code within the periods covered under Provision 275(1,2) of the EDN Code.

SECTION 8. RULES AND PROCEDURES TO IMPROVE THE PERFORMANCE EFFICIENCY OF THE DISTRIBUTION NETWORK

CHAPTER 37. GENERAL PROVISIONS

277. The Distributor shall take continuous measures to improve the performance efficiency of distribution during the operation and planning of the Distribution Network, particularly in the areas of reducing operation and maintenance costs, improving service quality indicators, reducing losses, and introducing modern technologies for management and metering.
278. The Distributor shall provide for efficient and reliable operation of the Distribution Network using modern and effective planning tools.
279. The Distributor shall be required to apply modern modeling software packages for computer modeling and optimization of the distribution network. The modeling software must meet the distribution network planning requirements and be able to analyze at least the following:
    1) Active and reactive power demand;
    2) Load flows:
    3) Short circuit current;
    4) Voltage regulation;
    5) Assessment of the electricity system behavior related to Normal and Critical regimes of the distribution network;
    6) Consumption (load) forecast;
    7) Other voltage-related characteristics.
280. The Distributor shall be well informed about the technical specifications of its Distribution Network, including data, service life, and maintenance periods for the equipment owned by other entities and under its operational control.

CHAPTER 38. SERVICE QUALITY INDICATORS

281. In case of Customers whose electricity supply is to be implemented with 2 or more 6 kV and higher voltage autonomously fed overhead lines (cables) or from 2 stationary systems or sections of the plant (substation), the Distributor shall be required to restore electricity supply after an unplanned interruption no later than:
    1) Within 3 hours starting in 2025 and within 2 hours starting in 2027 for residential settlements of administrative areas of urban municipalities;
    2) Within 6 hours starting in 2025 and within 4 hours starting in 2027 for residential settlements of administrative areas of rural municipalities.
282. Starting in the year 2025, the annual electricity supply interruption indicators (SAIDI and SAIFI) shall not exceed 75 percent of the 2021 indicators, and starting in 2028, they shall not exceed 55 percent of the 2025 indicators.
283. Starting in the year 2025, the overall number of deviations from permissible voltage ranges on an annual basis shall not exceed 50 percent of the 2021 indicators, and starting in 2028, such cases should be completely excluded.
284. Metering devices should be installed in such a way as to minimize the possibility of their mechanical damage or unacceptable impact on the environment and of interference by unauthorized persons into the connection scheme of the Metering device and its operation.
285. In case of branching of 1 kV and higher voltage lines of the Distribution Network, automatic switching equipment shall be installed.

CHAPTER 39. AUTOMATED METERING SYSTEMS

286. The Distributor shall be required to introduce an Automated metering system by the end of 2027 as per the program agreed with the Commission, enabling automatic metering of electricity consumed by all Customers of the Distribution Network.

CHAPTER 40. ELECTRONIC MAPS

287. The Distributor shall be required to prepare appropriate electronic maps in the format of a geographic information map.
288. All changes to the Distribution Network shall be incorporated into applicable maps by the Distributor.

CHAPTER 41. LOSS REDUCTION MEASURES

289. The Distributor shall regularly improve the technologies and operating procedures used while designing and constructing the network upgrades.
290. The Distributor shall be required to take measures to reduce losses in the Distribution Network, namely:
    1) Select the diameter and length of electric transmission lines in the low voltage network in such a manner that the voltage drop does not exceed 5 percent along the entire line;
    2) Where new transformers are to be installed, choose transformers capable of voltage regulation;
    3) Build the Distribution Network in such a manner as to minimize the length of the low- voltage transmission line coming out from the transformer point and reaching the load point;
    4) Select technically and economically approved transformers of high nominal voltage levels (within reasonable ranges);
    5) Compensate for reactive power, increasing the Distributor's ability to meet the power factor requirements as established by the EDN Code;
    6) Build low-voltage lines with insulated wires;
    7) Design transformer stations in a site close to Customer groups (centralized near the load) so that the Customers fed from it are an equal distance away from the transformer (if practically possible);
    8) Through specific computer programs, provide for the implementation of loss analysis and their structural division;
    9) Take other adequate measures. In the future, with the use of a deep penetration mechanism, the operation of low-voltage networks exceeding 600 meters within its service area will be eliminated;
    10) Reduce the number of 35–110 kV substations operated by one transformer.

SECTION 9. TRANSITIONAL PROVISIONS

CHAPTER 42. LOSS REDUCTION MEASURES

291. In terms of reactive energy, Provisions 73 and 74(3), 241, 247, 279, and 290 of the EDN Code shall come into effect starting January 1, 2025.

292. Chapter 40 and Provision 283 of the EDN Code shall come to effect starting January 1, 2028.

ANNEX 1. PROCEDURE FOR ELECTRONIC SUBMISSION OF DOCUMENTS REQUIRED FOR CONNECTION OF A RECONSTRUCTED CONSUMPTION FACILITY OF A NEW CUSTOMER OR A CUSTOMER TO THE DISTRIBUTION NETWORK

1. This procedure defines the requirements for electronic submission of documents to the Distributor, at the discretion of the Applicant, defined in Provision 159 of the EDN Code for connection of a reconstructed consumption system of the New Customer or the Customer to the Distribution Network (hereinafter, the Connection Application).
2. Connection Applications in an electronic format shall be submitted to the Distributor via the official website of the latter.
3. In addition to filling out the Connection Application on the website specified in Provision 2 of this Procedure, the Applicant shall also send to the Distributor the scanned copies of the documents prescribed by Provision 159 of the EDN Code in any of the following file formats: DOC, DOCX, PDF, or JPEG.
4. The Connection Application shall be considered submitted on the day it was registered on the Distributor's official website. The fact that the Connection Application has been registered on the Distributor's website shall be confirmed by the notification received immediately after registration of the Application in the electronic system, which contains an x-digit code.
5. Within 1 business day after receiving the Connection Application, the Distributor shall examine it and inform the Applicant of its acceptance or rejection (if the information and materials (documents) are incomplete) via the email address and telephone number indicated in the Application form. In addition, the results of the application examination shall be also displayed in the Distributor's electronic system.
6. In the case of receiving a warning about missing documents, the Applicant may send scanned copies of the missing documents or corrected documents.
7. The Applicant shall provide the required new documents or materials as prescribed by Provision 6 of this Procedure in addition to the Application submitted by accessing the system with the already provided x-digit code.
8. The Applicant may access the electronic system with the provided x-digit code, where the following information is displayed:
   1) Connection Application number;
   2) Date of acceptance of the Connection Application in the electronic system of the Distributor;
   3) Applicant's name, surname, place of residence (in case of a legal entity: name, location);
   4) Required capacity and voltage level;
   5) Connection type (single-phase, 3-phase);
   6) Date of submitting a proposal for a contract;
   7) Date of providing actual electricity supply (possibility of electricity supply);
   8) Deadline for payment of the connection fee, including the advance payment deadline;
   9) Other conditions (if applicable).
9. The Distributor shall send a reminder to the Applicant the day before the deadline for the payment of the connection fee (including the advance payment deadline) to the email address specified in the Connection Application.

10. Starting the date of notification of acceptance of the Connection Application, the Distributor shall proceed with the Connection Application received through the electronic system in accordance with the procedure set forth in the EDN Code.
11. After the Connection Application has been received in the Distributor's electronic system and the respective actions have been finalized in the manner and terms specified in the EDN Code, the Distributor, through the email address and phone number specified in the Application, shall send to the Applicant a proposal on concluding a contract by uploading a unilaterally signed Contract into the Distributor's electronic system.
12. The original Contract shall be signed when the authentic copies of the electronically attached documents, which, according to the requirements of the EDN Code, should be submitted to the Distributor in their original form, have been provided.
13. The Distributor shall immediately compare the original documents specified in Provision 12 of this Procedure with the scanned copies of the documents attached to the Application in order to ensure that they are reliable, after which the original documents shall be returned to the Applicant. No Connection Application shall be signed unless the original documents are provided.

ANNEX 2. APPLICATION FOR GENERATOR CONNECTION

1.	**Applicant's data**					
1)	Name					
2)	Type	Generator				
		Customer				
3)	Name of electric facility					
4)	Address of electric facility					
5)	Cadastral surface of the facility location site (including positional image)					
6)	Purpose of connection	Connection of a new facility				
		Capacity increase by Generator				
		Modernization of the existing facility				
7)	Planned capacity of connection or planned capacity increase (MW)					
8)	Planned voltage level of the Connection point (kV)					
9)	Implementation by stage (yes/no)					
10)	Scheduled deadlines for construction/upgrade (by stage)	Stage	I	II	III	IV
		Year/month				
		MW				
11)	Applicant's address					
12)	Applicant's phone number					
13)	Applicant's fax number					
14)	Responsible person	Name, surname				
		Address				
		Email				
		Phone				

To be filled in by Generators

2	Data on generation facility					
1)	Power plant	Run-of-river HPP				
		HPP with reservoir				
		Pumped SPS				
		ANPP				
		TPP				
		Combined cycle				
		Wind				
		Other (specify)				
2)	Fuel	Coal				
		Gas				
		Mazut				
		Nuclear				
		Other (specify)				
3)	Energy data by stage	I	II	III	IV	
a.	Number of units (items)					
b.	Active power production (MW)					
c.	Maximum capacity to be delivered (MW)					
d.	Annual output forecast (MWh)					
4)	Reactive power regulation availability (yes/no)					

ANNEX 3. AGGREGATE ESTIMATION OF CONNECTION FEES

DISTRIBUTOR

_____

(position, signature, name, surname)

___ _____20____

GENERATOR

_____

(position, signature, name, surname)

_____20____

___

Agreed with

SYSTEM OPERATOR

_____

(position, signature, name, surname)

___ _____20____

ANNEX 4. CONNECTION FEES

Table 1

Methodology 1. Standard connection fees for the connection of private houses or commercial customers with 0.4 (0.22) kV voltage

1. Standard connection fees for private houses or commercial customers with 0.22 kV Consumption Systems shall be determined according to the following table:

Connection type	Maximum connection capacity	Standard connection fee Thousands of AMD (Value Added Tax included)	
		In the territory of Yerevan City	In the territory of the Republic of Armenia (except Yerevan City)
Single-phase (0.22 kV)	10 kVA	65	53
	14 kVA	91	62
Amplification of the connection	From 10 kVA to 14kVA	26	9

2. The standard connection fees (VAT included) for private houses or commercial customers with 0.4 kV Consumption Systems shall be determined by the following formula:

$$F_{st} = F_c + F_v \times R_c \times C_c,$$

where:

F_c is the value of fixed costs, accepted as equal to 203,000 (two hundred three thousand) AMD.

F_v value of variable costs, equal to 7,500 (seven thousand five hundred) AMD per kVA.

R_c is the required capacity by the Applicant (kVA).

C_c is the coefficient of costs, accepted to be equal to 1.4 within the administrative territory of Yerevan City, and equal to 1 within the other territories of the RoA.

Table 2. Single-phase connection fees for apartments in multi-apartment buildings and for Commercial customers

Thousands of AMD (VAT included)

Number of apartments and commercial customers with single-phase connection	Single-phase connection fee for one apartment or one commercial customer			
	10 kVA capacity		14 kVA capacity	
	1st zone	2nd zone	1st zone	2nd zone
Up to 25	66	55	92	58
25–40	59	48	83	50
41–60	52	41	75	45
61 or more	46	35	68	40

1st zone: Territory of Yerevan City

2nd zone: Territory of the Republic of Armenia, excluding the territory of Yerevan City

Methodology 2. Standard connection fees for commercial customers with 6(10) kV Consumption Systems

1. Standard connection fees (VAT included) for customers with 6(10) kV Consumption Systems shall be determined by the following formula:

$$F_{st} = F_c + F_v \times R_c \times C_c,$$

where:

Fc is the value of fixed costs, which is accepted as equal to 846,000 (eight hundred forty-six thousand) AMD,

Fv is the rate of variable costs, which is accepted as equal to 2,150 (two thousand one hundred fifty) AMD, per kVA.

Rc is the required capacity by the Applicant (kVA).

Cc is the coefficient of costs, which is accepted as equal to 1.4 for the administrative area of Yerevan City and equal to 1 for other territories of the RoA.

Table 4. Standard and Additional Connection Fees for Commercial Customers to be Connected to the 35 kV Voltage Network

Millions of AMD (VAT included)

Capacity to be connected	Standard connection fee for up to 12 km of the connecting line	Additional fee for every 250 m exceeding 12 km
<3,000 kVA	21.70	1.28
3,001–4,000	26.19	1.70
4,001–5,000	30.67	2.13
5,001–6,000	35.15	2.55
6,001–7,000	39.63	3.00
7,001–8,000	44.11	3.40
8,001–9,000	48.59	3.83
9,001–10,000	53.08	4.25
10,001–11,000	57.56	4.68
11,001–12,000	62.04	5.10
12,001–13,000	66.52	5.53
13,001–14,000	71.00	5.95
14,001–15,000	75.48	6.38

ABBREVIATIONS LIST

1. AAF	Annual Adequacy Forecast
2. AEAM	Automated elimination of asynchronous mode
3. AECS	Automated Emergency Control System
4. ALFD	Automatic limitation of frequency drop
5. ALSFDR	Automated load shedding by frequency down rate
6. AMIR	The cross-border interconnection line between Iran and Armenia
7. ANPP	Nuclear power plant
8. APEIO	Automated prevention of equipment from impermissible overloading
9. APIEO	Automated prevention of impermissible equipment overloading system
10. APP	Autonomous Power Producer
11. APSV	Automated prevention of stability violation
12. ARC	Automatic Recloser
13. ARF	Automated reclosing by frequency
14. AS	Electricity system automatic separation from the neighboring system
15. ASFD	Automated separation by frequency drop at the stations
16. ASLF	Automated start-up and loading by frequency
17. ASTPM	Automated System for Technological Process Management
18. ASEMC	Automated system of electricity metering and control
19. BALM	Balancing Market
20. BRPA	WEM Trade Participant who has joined another participant's balancing Group, authorizing the latter to bear its balancing responsibility
21. BRPG	WEM Trade Participant who has assumed responsibility for imbalances of another WEM Trade Participant or has formed a balancing group
22. BRPI	WEM Trade Participant who has assumed the status of an independent balance responsible party
23. BRPP	WEM Trade Participant who has joined another participant's balancing group by authorizing the latter to trade electricity in the WEM on its behalf, undertake balancing responsibility, and pay for services
24. BSP	A Generator providing Balancing services under electricity generation license
25. CFBD	Circuit Failure Back-up Device
26. CPP plants	Generators operating in competitive conditions
27. DAM	Day-Ahead Market
28. DAMS	Automated System of Electricity Metering And Control

29. DAS	Automated Data Acquisition System
30. DCTD	Data collection and transmission device
31. DLOS	Distribution Network losses and own needs for the Distribution Network
32. DNDF	Customers connected to the Distribution Network
33. DOMPs	Transmitter, Generators, Customers that are required to have operative personnel (responsible for electric facilities) as prescribed by the technical regulation approved by the RoA Government
34. DOPP	Distribution-Scale Plants and Large Customers
35. EDEM	Annual forecast of electricity demand, including its adjustments on a monthly and daily basis
36. EDN Code	Republic of Armenia Electricity Market Distribution Network Code approved by the Commission
37. EGEN	Annual forecast of electricity generation mix, including its adjustments on a monthly and daily basis
38. ELTP Participants	Utility-Scale Plants, Transmitter, Distributor, Utility-Scale Customers
39. ELTRANS	Annual forecast of Transmission Network losses, including their adjustments on a monthly and daily basis
40. EMO	Electricity Market Operator
41. EOM Participants	Balancing Service Provider, Transmitter, Distributor, Utility-Scale Plants, Utility Scale Customers
42. EPOS	Annual schedule of planned outages of the electricity system, including its adjustments on a monthly and daily basis
43. ERSL	Annual reliability and security level of the electricity system, including its adjustments on a monthly and daily basis
44. ESO	Electricity System Operator
45. ESTPO Participants	Utility-Scale Plants, Transmitter, Distributor (only for substations and electricity transmission lines directly connected to the Transmitter), and Utility-Scale Customers
46. ETN Code	Republic of Armenia Electricity Transmission Network Code approved by the Commission
47. GEAM	The cross-border interconnection line between Georgia and Armenia
48. IPP plants	Generators operating under the Public-Private Partnership
49. LC	Long-Term Contracts Component of the Bilateral Contracts Market
50. LSF	Automated load shedding by frequency
51. LSF-1	Automated elimination of frequency drop
52. LSF-2	Automated restoration of frequency
53. LTPL	Long-term permissible load
54. MMS	Market Management System
55. NRC	Non-Regulated Component of Bilateral Contracts Market

56. OLTC	On-load transformer changer
57. PFI	Protection against frequency increase
58. PPP	Public-Private Partnership
59. RC	Regulated component of the Bilateral Contracts Market
60. REM Rules	Republic of Armenia Retail Electricity Market Trading Rules approved by the Commission
61. REM Participants	Universal Supplier, Suppliers,, Customers (except for Qualified Customers), and Autonomous Power Producers
62. REPP plants	Hydropower plants and plants operating using other renewable energy sources (wind, solar, geothermal, and biomass) under 30 MW capacity, except for IPP plants, with the Power Purchase Guarantee as provided for by the Law
63. RES	Renewable Energy Sources
64. RES APP	Autonomous Power Producers using Renewable energy sources
65. RPAEC	Relay Protection and Automatic Emergency Control
66. RPP plants	Generators subject to tariff regulation, except for IPP plants, REPP plants, and the Balancing Service providing Generator
67. RS Indicators	Reliability and security indicators
68. SAIDI	System Average Interruption Duration Index
69. SAIFI	System Average Interruption Frequency Index
70. SALS	Special automated load shutdown
71. SC	Short circuit
72. SCADA	Supervisory Control and Data Acquisition
73. STPL	Short-term permissible load
74. TD	Trading Day
75. TD+1	One day after the Trading Day
76. TD-1	One day before the Trading Day
77. TL	Transmission line
78. TYNDP	Ten-Year Network Development Plan
79. VDAL	Voltage down automated limitation
80. VUAL	Voltage up automated limitation
81. WEM Contract	A contract between WEM Participants for participation in the WEM
82. WEM Participants	Generator, Universal Supplier, Supplier, Trader, Qualified Customer, Transmitter, Distributor, ESO, and EMO
83. WEM Rules	Wholesale Electricity Market Trading Rules of the Republic of Armenia.

RULES AND CONTRACTS OF THE ELECTRICITY MARKET OF THE REPUBLIC OF ARMENIA

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